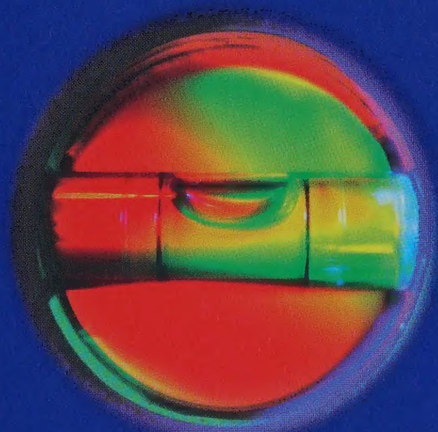
blue mountain
energy ltd



BALANCING RISK AND REWARD

2004 ANNUAL REPORT

Blue Mountain Energy Ltd. is a Calgary, Alberta-based oil and natural gas producer focused on growth through exploration and development drilling. The Company's business model also includes growth through acquisitions that are operationally complementary and that increase Blue Mountain's exploration opportunities. Blue Mountain's activities are focused in three core areas: West Central Alberta, Peace River Arch and Northeast British Columbia.

In 2004 Blue Mountain drilled 33 (25 net) wells which, coupled with the acquisition of Sentra Resources Ltd, grew production to a fourth quarter rate of 2,700 boe per day, an increase of 44 percent from fourth quarter 2003. Year-end net undeveloped land holdings increased 136 percent to 140,000 acres.

In 2004 Blue Mountain generated cash flow of $17 million ($1.09 per share) and was earnings-positive at $0.09 per share. The Company's 2005 capital program is budgeted at $40 million and includes a planned 40 gross wells.

Blue Mountain is a publicly-traded company listed on the TSX under the symbol GAS. At December 31, 2004 the Company had 21.3 million common shares outstanding.

Blue Mountain's annual general meeting will be held on Thursday, May 19, 2005 at 3:00 PM MST in the Strand/Tivoli Room at The Metropolitan Centre, 333-4th Avenue S.W., Calgary, AB T2P 0H9.

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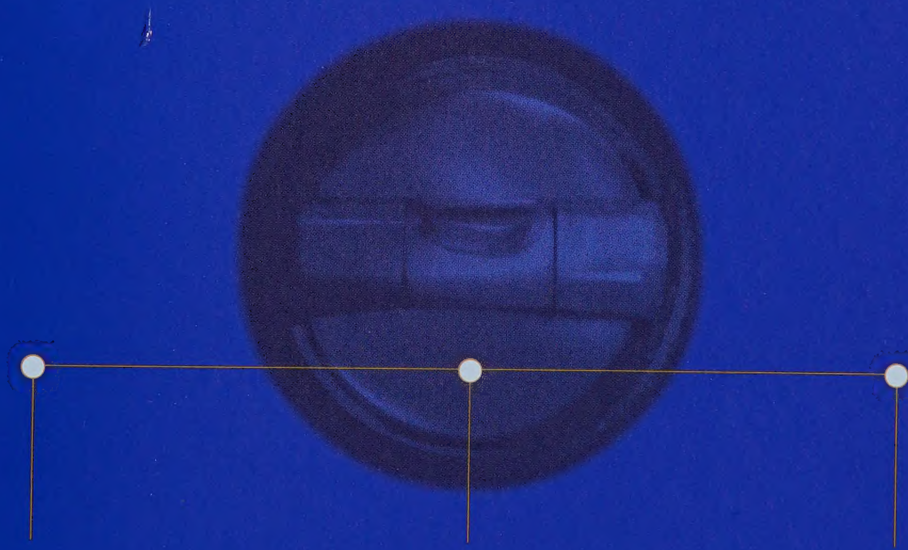
We're an exploration company. Pure and simple.

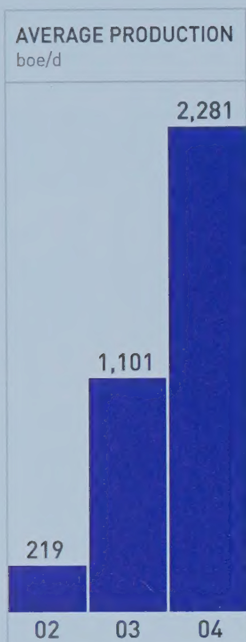
With a balanced approach to risk.



Strong balance sheet with limited debt

Farm-out selective high-risk drilling targets to major industry partners

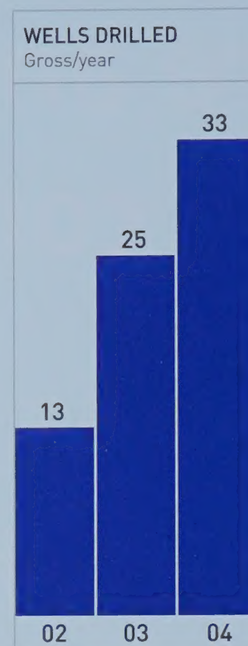
Adding partners on a promoted basis on Blue Mountain-operated drilling projects



Corporate Strategy

Blue Mountain is a financially-disciplined, grassroots exploration company.

- The Company averaged production in 2004 of 2,281 boe per day.
- Q1 2005 production will average approximately 2,800 boe per day, weighted 75 percent to natural gas.
- The Company uses debt prudently to supplement financing of capital spending.

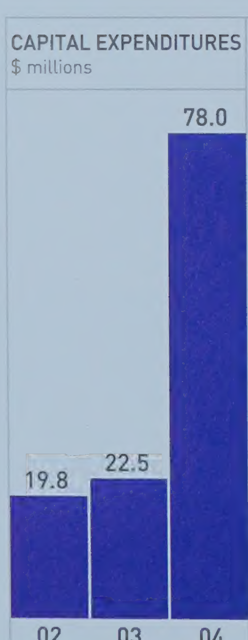


Exploration Strategy

Blue Mountain focuses on internally generating prospects in West Central Alberta and the Peace River Arch.

- 2004 capital program of $38 million included $21 million on drilling/completions.
- Net P+P reserve additions replaced 2004 production by 270 percent.

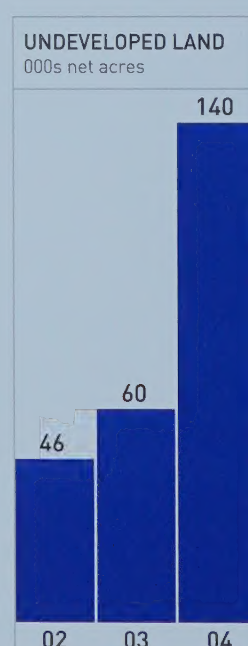
Building value through a balanced drill-bit approach



Acquisitions Strategy

Selective acquisitions are accretive to production, reserves, cash flow and prospect inventory.

- $40 million acquisition of Sentra Resources added 1,300 boe per day, weighted 63 percent to natural gas; 73,000 net acres of undeveloped land and $45 million of tax pools.



Development Strategy

Blue Mountain has significant undeveloped land holdings which allow the Company to follow-up any oil or natural gas discovery with a development program.

- The Company increased its undeveloped land holdings by 136 percent in 2004 through a combination of Crown sales and the acquisition of Sentra.

Highlights

	Twelve months ended December 31		
	2004	2003	% Change
Average Production			
Crude oil (bbls/day)	**704**	491	43
Natural gas (mcf/day)	**8,297**	3,271	154
Natural gas liquids (bbls/day)	**194**	65	198
Total (boe/day)	**2,281**	1,101	107
Average Prices			
Crude oil ($/bbl)	**$ 36.22**	$ 27.67	31
Natural gas ($/mcf)	**6.94**	6.58	5
Natural gas liquids ($/bbl)	**38.69**	30.45	27
BOE ($/boe)	**39.73**	33.67	18
Operating Netbacks			
Crude oil ($/bbl)	**$ 18.38**	$ 12.68	45
Natural gas ($/mcf)	**4.06**	4.53	(10)
Natural gas liquids ($/bbl)	**20.58**	16.10	28
BOE ($/boe)	**22.20**	20.07	11
Financial ($ thousands except per share amounts)			
Gross revenues	**$ 33,189**	$ 13,696	142
Cash flow	**16,838**	7,250	132
Cash flow per share			
Basic	**1.09**	0.58	88
Diluted	**1.03**	0.55	87
Earnings	**1,417**	1,602	(12)
Earnings per share			
Basic	**0.09**	0.13	(31)
Diluted	**0.09**	0.12	(25)
Net capital expenditures	**77,989**	22,485	247
Cash and cash equivalents	**–**	9,687	(100)
Net working capital (deficiency)	**(11,440)**	9,856	(216)
Common shares outstanding	**21,262**	14,107	51
Warrants outstanding	**460**	1,154	(60)
Stock options outstanding	**1,901**	1,341	42

Letter to shareholders

Blue Mountain's dramatic activity in 2004 has provided a solid foundation for our exploration and development program in 2005. The Company's 33 gross wells drilled in 2004, of which approximately 70 percent targeted natural gas, our aggressive land acquisition program, and a corporate acquisition that added 1,300 boe in daily volumes as well as nearly doubling Blue Mountain's undeveloped lands, position us solidly for a harvesting of opportunities in 2005.

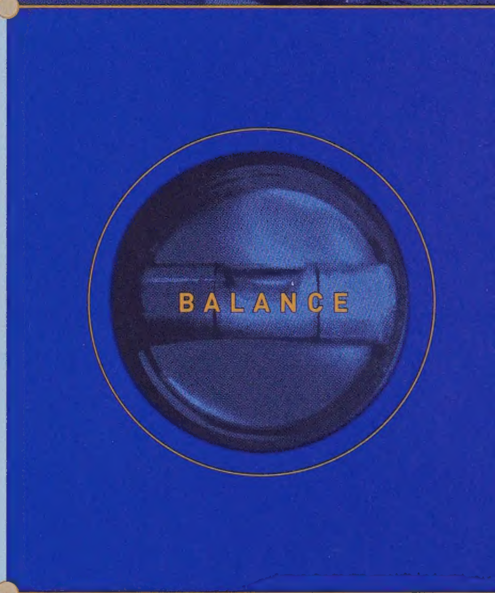
2004 highlights

- Daily average production increased by 107 percent year-over-year, to 2,281 boe per day, of which 60 percent was natural gas. Fourth quarter production grew to 2,693 boe per day;
- Commenced construction on the Spirit River project. At the end of March 2005, Spirit River proper was producing 1,420 boe per day gross, 900 boe per day net, with an additional 400 boe per day to be placed on production from Spirit River North within two weeks;
- Record capital program of $38 million (not including the acquisition of Sentra Resources Corporation), including 33 gross (25 net) wells drilled, apportioned as follows: $5 million on undeveloped lands, $4 million on expanding the Spirit River core area through a small acquisition, $21 million on drilling/completions and $5.8 million on production facilities;
- Proved plus probable reserves increased by 59 percent, replacing 270 percent of 2004 production on a proved plus probable basis (159 percent on a proved basis);
- Cash flow of $17 million ($1.09 per share), a year-over-year increase of 132 percent and 88 percent, respectively;

- $40 million corporate acquisition of Sentra Resources Corporation, adding production of 1,300 boe per day (63 percent natural gas) and 73,000 net acres of undeveloped land, with $45 million of tax pools; and
- Net Company undeveloped land increased by 136 percent to 140,000 net acres.

Blue Mountain's growth record

When we formed the Company in 2002, Blue Mountain did not have a single drillable prospect nor an acre of undeveloped land. Over the following two-and-a-half years we were able to establish a foothold by Crown postings and farm-ins on prospects held by major companies. As we gained access to prospects we began drilling a number of high-risk/high-reward exploration wells, as well as lower-risk development wells, usually at very high working interest. This approach, coupled with the acquisition of Bolt Energy Ltd., allowed us to grow Blue Mountain's daily volumes to 2,500 boe per day by early 2004, and to assemble a base of prospects and undeveloped lands of approximately 60,000 net acres.



The dramatic rise in commodity prices, however, made it clear that Blue Mountain's preferred avenue was drawing to an end. To maintain the internal prospect inventory, Blue Mountain increased its participation in Crown sales. But we also recognized that we should no longer refuse opportunities to grow through acquisitions. When we identified the opportunity to purchase Sentra, we saw not only substantial current production and tax pools of $45 million, but 73,000 net acres of highly prospective undeveloped lands. The acquisition closed on September 30, 2004. The key acquisition metric, less than $31,000 per daily flowing boe, is advantageous to Blue Mountain's shareholders and compares well against prevailing acquisition prices.

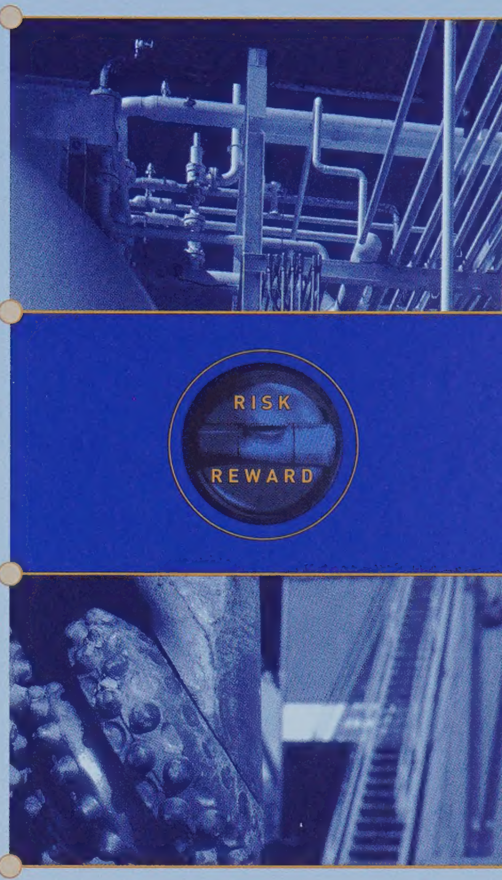
The benefits of Blue Mountain's aggressive land acquisition, which is crucial to maintaining an inventory of drilling prospects, will be felt in future years.

At the end of 2004, Blue Mountain has grown into a company producing nearly 2,700 boe per day, of which 75 percent is natural gas, with $95 million in tax pools, 140,000 net acres of undeveloped land and still only 22 million common shares outstanding.

Reserves and F&D costs

Blue Mountain's 2004 exploration, development and acquisition program achieved proved plus probable reserve additions of 3.1 million boe. While the three-year average finding and development (F&D) cost of $14.93 per boe of reserves added is acceptable, we are not pleased with the 2004 cost of $25.82 per boe. However, this result should be considered in the following context:

- Considerable capital was expended to place previously drilled wells on-stream, which mainly generated established reserves attributable to 2003. Capital expenditures were also required to twin the sour 9-16 well to produce the sour zone.
- Blue Mountain's aggressive land acquisition program, which is crucial to maintaining an inventory of drilling prospects that meet our particular technical criteria. The benefits of these expenditures, which are included in the current year's F&D cost, will be felt in future years.
- Poor results with the Kiskatinaw exploration program. All eight Kiskatinaw wells drilled in 2004 were non-productive. The Kiskatinaw Formation is well-known for its risk – offset by its high-impact potential. Kiskatinaw wells can have extremely high productivity, with significant reserves. In 2004, this challenging formation treated us miserably. This year could very well be different, although we will reduce our exposure somewhat.



Strategic shift

Our strategic position established in the Peace River Arch and West Central Alberta will allow us to take a more balanced approach to exploration beginning in 2005. The substantial inventory of drilling prospects identified by our group is being complemented by recent agreements with other companies, four of them major producers, to farm-in on undeveloped lands held by Blue Mountain. These lands are highly prospective and are closely offset by exciting new developments being conducted by area competitors.

The farm-in partner companies will fund and drill wells on undeveloped lands provided by Blue Mountain. We will retain a minimum 40 percent working interest and will be assured of equitable production rates from any successes in these high-impact targets. In most cases, Blue Mountain will earn its share of production by supplying the land, and then funding only its proportionate share of the tie-in costs of any discoveries. We will also have assured access to the operator's processing capacity for our production volumes. Based on pending agreements, we anticipate 2005 exploration spending of $5-$8 million by our farm-in partners on Blue Mountain's lands. This outside capital spending and drilling activity is supplemental to Blue Mountain's internal budget and planned number of wells. This new approach will substantially leverage our internal exploration drilling budget of $8 million while reducing exploration and capital risks to Blue Mountain's shareholders.

The Company still intends to have a component of higher-risk, higher-potential prospects in its portfolio, but the proportion will be reduced, focusing the majority of the drilling on medium-risk exploration. As well, Blue Mountain's internal exploration program will be enhanced by risk-sharing with partners on a promoted basis.

Our strategic position established in the Peace River Arch and West Central Alberta will allow us to take a more balanced approach to exploration beginning in 2005.

This year's capital program is budgeted at $40 million and will include a planned 40 gross wells, plus the wells drilled by other operators on our behalf.

2005 outlook

Blue Mountain enters 2005 with a focused and balanced exploration strategy. This year's capital program is budgeted at $40 million and will include a planned 40 gross wells, plus the wells drilled by other operators on our behalf. The Company is well-financed to operate using a mix of internal cash flow and a modest increase in debt. Our holdings of strategic parcels of highly prospective lands will leverage our exposure to high-impact exploration opportunities at little or no further cost to the Company, until success is established.

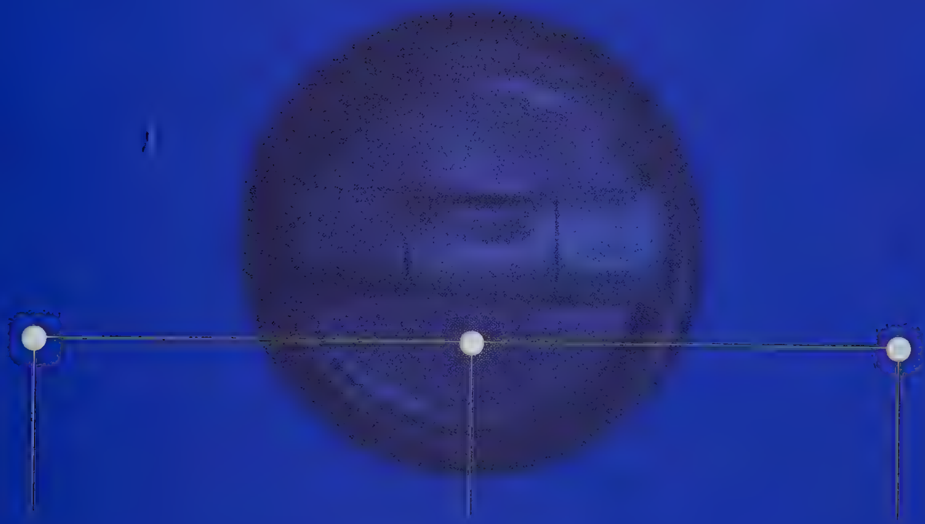
Throughout the course of the Blue Mountain team members' exploration careers, we have seen years with exemplary results and years with less than exemplary results. Our mix of prospects and opportunities this year suggest 2005 could be an exemplary year, if we have even reasonable luck in overcoming the irreducible risks that always accompany an exploration program.

On behalf of the Board of Directors,

Randy Pawliw
President and Chief Executive Officer
March 20, 2005

Exploration and development review

A balanced approach to prospect generation.

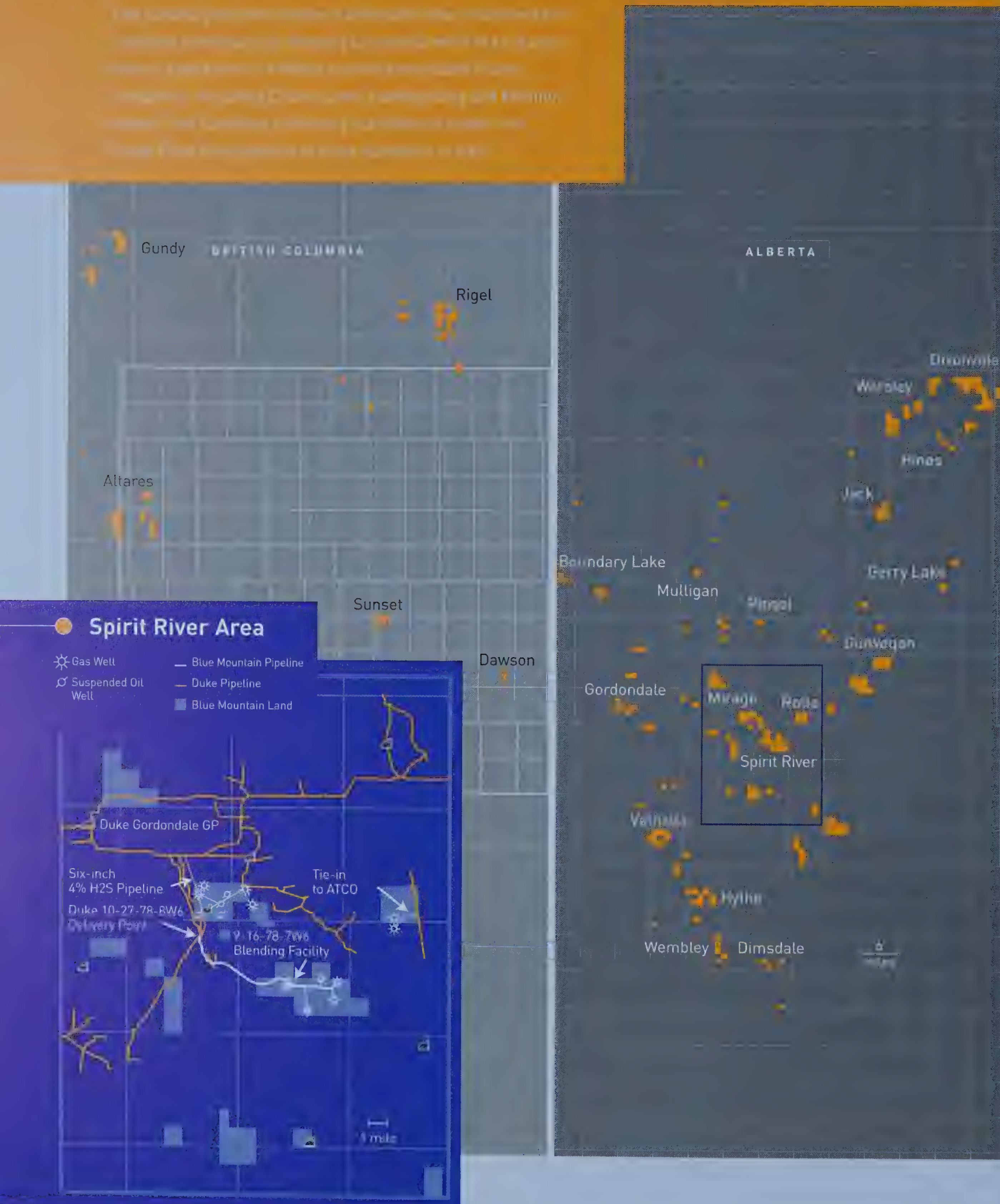


140,000 acres of undeveloped land

Talented prospect-generation team

Inventory of short-term drillable locations and long-term exploration concepts

Peace River Arch and Northeast British Columbia



Peace River Arch

Blue Mountain's net production from the Peace River Arch is expected to reach 1,700 boe per day by the end of the first quarter of 2005, or one-half of the total corporate production. The Company holds 119,000 (88,800 net) acres of undeveloped land in the region, of which 91,000 (70,000 net) acres are undeveloped.

Blue Mountain drilled 24 wells in the Peace River Arch during 2004, including 10 (7.45 net) in the Spirit River area, three (2.52 net) in the Worsley area, and 13 (8.92 net) wells that targeted new pool wildcats.

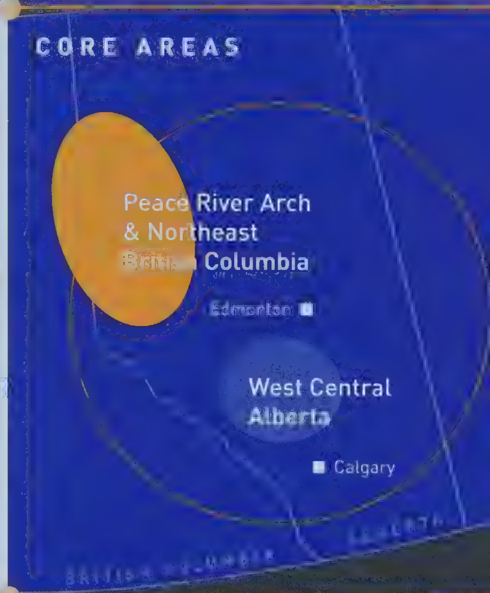
Eight of the 13 wells targeted the Kiskatinaw Formation. While we expect to drill three or four Kiskatinaw prospects in the Peace River Arch in 2005, our focus has shifted to the somewhat more predictable Triassic formations, where we have budgeted for 16 wells targeting the Charlie Lake, Halfway/Doig or Montney formations. The Kiskatinaw is one of the most risky exploration targets; when successful, however, it is also one of the most prolific. The Triassic formations, on the other hand, generally offer a higher probability of success, with a somewhat smaller prize.

In addition to our own drilling plans, Blue Mountain has received several exciting proposals from other operators to drill our Peace River Arch acreage. We expect these companies will spend \$3-\$6 million on our behalf to drill two to four wells, in which Blue Mountain would retain a 40 percent working interest. In addition to having others take on the risk capital of these projects, Blue Mountain is assured that its share of production from successful wells will be processed through the operators' facilities.

Spirit River area

The greater Sprit River area, which encompasses Mirage, Rolla and the original Spirit River property, contributes approximately 80 percent of the Peace River Arch production.

In the greater Spirit River area, the Company drilled seven (5.75 net) successful gas wells at Mirage, Rolla and Spirit River. Three (2.92 net) new shallow gas wells drilled at Mirage in 2004 will be on full production by the end of March. One well placed on production last fall is being optimized, and the other two will commence production in March following completion of a compressor facility upgrade. Total net additional production from Mirage will be 320 boe per day. At Rolla, Blue Mountain will complete final tie-in of two (1.5 net) wells in March, which will add 130 boe per day net.



At Worsley the Company drilled a successful natural gas wildcat in the first quarter of 2005, which followed two (1.9 net) development oil wells drilled in summer 2004 and in the first quarter of 2005.

At Spirit River, the Company completed and equipped a twin (1.0 net) to the original Belloy discovery well and drilled and completed one (0.33 net) very successful new well in two separate zones. The two wells were brought on-production in March following completion of the long-awaited Duke pipeline lateral. The two wells are expected to add net production of 800 boe per day.

Total production from the greater Spirit River area is expected to reach 1,360 boe per day by mid-April 2005. The Company has 18,210 (15,159 net) acres in the area, including 10,560 (9,650 net) which are undeveloped. In 2005, the Company plans to drill one or two further Triassic wells at Spirit River and a shallow Dunvegan well at Mirage.

Gordondale

While Gordondale currently produces approximately 60 boe per day net, the Company sees upside in the property and plans additional drilling in Q2 2005. As well, an existing well will revert to a 55 percent working interest in late summer, which will provide additional production of approximately 200 boe per day net. Blue Mountain holds 5,280 (2,730 net) acres in this area.

Worsley

The Company drilled a successful natural gas wildcat in the first quarter of 2005, which followed two (1.9 net) development oil wells drilled in summer 2004 and in the first quarter of 2005. Blue Mountain's original oil discovery, drilled in early 2004, was completed for two zones, including an up-hole gas zone and the original oil zone. The Company had planned to drill a third development oil well in March, but early road bans halted activity. Instead, the Company plans to drill the oil well and install pipeline tie-ins to the natural gas discovery and the gas zone in the original well next winter. Worsley is one of the few winter-access only properties owned by Blue Mountain. Consequently, the Company currently has approximately 240 boe per day behind pipe. Blue Mountain has 7,040 (6,090 net) acres in the area.

Boundary Lake

Blue Mountain made a new pool natural gas discovery (0.76 net) in late 2004 which is expected to produce 60 boe per day when tied-in after spring break-up. The Company has defined additional drilling locations on the project and may consider down-spacing to two wells per section once the pool has been delineated. The Company holds 1,920 (1,459 net) acres of land at Boundary Lake.

Other

At Bilawchuk, the Company's plans to drill two (1.39 net) wells in March were delayed due to early spring break-up. The Company will drill one (0.5 net) well during the summer, and the other next winter after the ground is frozen. Two (1.0 net) Triassic wells at Woking and one (0.61 net) Triassic well at Dimsdale are planned for mid-summer. In addition, the Company has a number of prospects which are expected to be drilled during 2005. We are unable to provide further information on these projects at this time for competitive reasons.

Northeast British Columbia

Northeast B.C. is a new core area that was acquired through the Sentra acquisition in 2004. Blue Mountain has wells planned for 2005 at Rigel, Gundy and Altares. Net production from northeast B.C. is currently 160 boe per day, all from the Rigel property. The Company has 37,175 (17,500 net) acres in northeast B.C., of which 27,100 (11,500 net) are undeveloped.

Rigel

The property, operated by Progress Energy Trust, produces 160 boe per day net to the Company. In the first quarter of 2005, Blue Mountain drilled one (0.6 net) well, and recompleted two (1.05 net) wells. These wells, which are expected to produce 85 boe per day net, are expected to be tied-in next winter. The Company's working interests in the wells are 45–60 percent. Blue Mountain has 11,800 (7,400 net) acres at Rigel.

Gundy

The Company has a 60 percent working interest in 2,827 acres of land in the Gundy area, where a Halfway trend is being developed on either side of the acreage. Blue Mountain has purchased 5.6 square miles of 3-D seismic over its acreage, and has defined a well location to be drilled next winter.

Altares

In the first quarter of 2005, Blue Mountain participated in the drilling of two wells on the Altares block, with a 14 percent and 12 percent working interest. The wells will be completed after spring break-up. The Company has 6,460 (834 net) acres at Altares.

Northeast B.C. is a new core area that was acquired through the Sentra acquisition in 2004. Blue Mountain has wells planned for 2005 at Rigel, Gundy and Altares.

West Central Alberta

West Central Alberta

The West Central area produces slightly less than 1,000 boe per day net to the Company. Blue Mountain holds 25,000 (18,000 net) acres of land, of which 11,700 (8,300 net) are undeveloped. The Company drilled eight wells in the area in 2004, including three (2.1 net) at Brazeau, three (2.5 net) at Knobhill, one (0.5 net) at Westerose, and one (0.95 net) at Ferrybank. All of the wells were cased and completed and seven were placed on-production by the end of the first quarter of 2005. In 2005 the Company plans to drill exploration targets at Brazeau and Edmonton sand development wells at Markerville.

Brazeau

During 2004 Blue Mountain drilled three (2.1 net) successful oil wells and completed a second zone (0.7 net) in the 7-31 discovery well. The property currently produces 55 boe per day net, with 80 boe per day net awaiting pooling and tie-in. During the first half of 2005 the wells will be tied into an existing battery and compressor facility to allow conservation and sale of solution gas. This is expected to result in lower operating costs.

South of the established property, Blue Mountain purchased 1,440 acres of land on a prolific Cardium trend. The Company scheduled a rig to drill two wells on the prospect in mid-March, but drilling was postponed due to the early spring break-up. The first well is now scheduled to drill immediately after break-up. Blue Mountain has 2,400 (2,025 net) acres at Brazeau.

Knobhill

The Company drilled three wells on this 100 percent working interest property in 2004, resulting in two oil wells and one natural gas well. Blue Mountain received Good Production Practice approval for its waterflood on February 10, 2005. The property is currently producing 390 boe per day.

In 2003, the Company negotiated a farm-in on a prolific Banff prospect in the area. The operator plans to drill and complete the well, then tie the well into facilities at preset fees. Because of landowner issues, the well has not yet been drilled. However, we have made major progress on the issues and expect the well will be drilled this summer. If successful, it will be placed on production by fall. Production rates could be in the 1-4 mmcf per day range. Blue Mountain would retain a 43 percent working interest in the well. The Company has 5,760 (4,839 net) acres in the Knobhill area.

Blue Mountain has farmed-out three sections at Westerose that were about to expire, in return for a non-convertible royalty.

Ferrybank

In December 2002 Blue Mountain drilled its first discovery well as a company at Ferrybank. Net production from the field was approximately 300 boe per day in 2004. Blue Mountain drilled one oil well (0.95 net) on this property in 2004. The Company is evaluating the economics of down-spacing the Glauconitic pool to two wells per section. It is possible that one or two wells will be drilled during 2005. The Company has 3,200 (2,955 net) acres in the Ferrybank area.

Westerose

The Westerose area currently produces approximately 120 boe per day net. In 2004 the Company drilled one (0.5 net) successful natural gas well on the property. The well was tied-in during March, resulting in an additional 50 boe per day net. In addition, Blue Mountain farmed-out three sections of lands that were about to expire. The partner is drilling multiple wells from a single pad to tap the shallow natural gas potential. Since the leases were set to expire, the Company will receive a non-convertible royalty on the wells. In addition, three 50 percent working-interest natural gas wells were drilled on acreage acquired from Sentra, in the general Westerose area. The wells have been tied-in and are on-production. Blue Mountain has 5,750 (3,339 net) acres in the Westerose area.

Markerville

Current production from Markerville is approximately 50 boe per day, including volumes from the new Edmonton natural gas zones that were completed in the two producing Cardium oil wells. In 2005 the Company plans to down-space the gas production by drilling two or three additional shallow Edmonton natural gas wells to more efficiently produce the numerous gas sands encountered. Blue Mountain has 2,324 (1,483 net) acres at Markerville.

Other

The Company has two oil-producing properties that contribute approximately 400 boe per day. Approximately 50 boe per day comes from Cantuar in southwest Saskatchewan and 350 boe per day from the Forest Bank heavy oil property, near Lloydminster, Saskatchewan. The Company's proved plus probable reserves increased by approximately 21 percent at Forestbank at year-end 2004. Oil production at this property continues to outperform estimates as higher rates have not led to significantly increased water cuts.

Management's discussion and analysis

This Management's Discussion and Analysis ("MD&A") for Blue Mountain Energy Ltd. ("Blue Mountain" or the "Company") should be read in conjunction with the audited consolidated financial statements and related notes for the years ended December 31, 2004 and 2003. The audited consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and measurement currency in the audited consolidated financial statements and in this MD&A is the Canadian dollar, unless otherwise stated.

In this MD&A, certain natural gas volumes have been converted to barrels of oil equivalent ("boe") using six thousand cubic feet (mcf) equal to one barrel (bbl) unless otherwise stated. This conversion ratio is based on an energy equivalent conversion applicable at the burner tip and does not represent a value equivalency at the wellhead.

This MD&A is dated March 22, 2005.

Non-GAAP measures

This MD&A uses the terms "cash flow", "cash flow from operations" and "cash flow from operations per share". Cash flow, cash flow from operations and cash flow from operations per share amounts are not measures that have any standardized meaning prescribed by Canadian GAAP and are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Management utilizes cash flow as a key measure to assess the ability of the Company to finance operating activities and capital expenditures. The terms "cash flow from operations" and "funds from operations" as presented in the consolidated financial statements are used synonymously.

Overview

Summary of 2004 performance

- Production volumes increased 107 percent to average 2,281 barrels of oil equivalent (boe) per day.
- Cash flow from operations was $16.8 million, an increase of 132 percent, and cash flow per share increased 88 percent to $1.09 per share.
- Drilled 33 gross (25.2 net) wells, resulting in 16 (11.9 net) gas wells and 9 (7.1) oil wells.
- Completed the acquisition of Sentra Resources Corporation ("Sentra") in September, which added approximately 1,300 boe per day of production, a new core area in northeastern British Columbia and, most importantly, over 73,000 net acres of undeveloped land, primarily in areas where Blue Mountain was already actively exploring.
- Completed a private placement in December, issuing 1,000,000 common shares at $8.25 per share and 500,000 flow-through shares at $10.60 per share, for gross proceeds of $13.6 million.
- Proved and probable reserves increased 59 percent and proved reserves increased 54 percent.
- Production was replaced 2.7 times on a proven and probable basis and 1.6 times on a proven basis.
- Net undeveloped land position increased by 136 percent.
- A $24 million line of credit was negotiated with a major Canadian bank.
- Total debt at the end of 2004 was less than 0.6 times annualized fourth quarter 2004 cash flow.
- Over 1,000 boe per day of production was in the process of being tied-in at year-end and is expected to be on production by the end of the first quarter 2005.

Annual financial summary ($000s except per share amounts)	2004	2004 vs 2003	2003	2003 vs 2002	2002
Revenues, net of royalties	26,424	127%	11,654	385%	2,405
Net earnings	1,417	(12%)	1,602	697%	201
per weighted average share – basic	0.09	(31%)	0.13	225%	0.04
per weighted average share – diluted	0.08	(33%)	0.12	200%	0.04
Cash flow from operations	16,838	132%	7,250	448%	1,324
per weighted average share – basic	1.09	88%	0.58	132%	0.25
per weighted average share – diluted	1.03	87%	0.55	120%	0.25
Total assets	128,957	124%	57,555	33%	43,285
Bank debt	(4,029)	100%	–	0%	–
Working capital (deficiency), excluding bank debt	(7,411)	(190%)	8,208	(44%)	14,726

Cash flow in 2004 increased primarily due to higher sales volumes aided by higher oil and natural gas liquids prices. Earnings decreased in 2004 mainly due to higher depletion expenses and also because earnings in 2003 benefited from a recovery of future taxes due to a reduction in the Canadian federal and Alberta corporate tax rates.

With the acquisition of Sentra in 2004 through a share exchange business combination, the Company assumed Sentra's debt and working capital deficiency which, along with working capital over and above cash flow from operations invested in exploration and development projects, resulted in a total debt and working capital deficiency of $11.4 million at the end of 2004.

The Company began generating earnings and cash flow as an oil and natural gas exploration and production company in September 2002.

Business environment

Blue Mountain's financial results are significantly influenced by its business environment. Risks include, but are not limited to:

- Crude oil and natural gas prices;
- Cost to find, develop, produce and deliver crude oil and natural gas;
- Demand for and ability to deliver natural gas;
- The exchange rate between the Canadian and U.S. dollars;
- Government regulations; and
- Cost of capital.

Commodity price risk

Blue Mountain's earnings and cash flow are significantly affected by fluctuations in oil and natural gas prices. Commodity prices have been, and are expected to continue to be, volatile due to a number of factors beyond Blue Mountain's control.

Commodity price and foreign exchange benchmarks	2004	2004 vs 2003	2003	2003 vs 2002	2002
AECO price (Cdn$ per mcf)	6.54	(2%)	6.67	64%	4.07
WTI price (US$ per bbl)	41.42	33%	31.14	19%	26.09
Edmonton par (Cdn$ per bbl)	52.91	22%	43.23	8%	40.12
Edmonton par/Lloydblend differential (Cdn$ per bbl)	16.733	9%	12.07	27%	9.53
Edmonton par/Bow River differential (Cdn$ per bbl)	14.93	46%	10.23	24%	8.27
Foreign exchange rate (US$/Cdn$)	0.77	7%	0.72	13%	0.64

Natural gas

The price of natural gas in North America is affected by regional supply and demand factors, particularly those affecting the United States such as weather conditions, pipeline delivery capacity, the availability of alternative sources of less costly energy supply, storage levels and general industry activity levels. Periodic imbalances between supply and demand for natural gas are common and result in volatile pricing. The price of natural gas, unlike crude oil, is not subject to the influence of an organization such as OPEC.

In 2004, natural gas prices remained relatively flat, declining by two percent from the 2003 average price. Although the NYMEX gas price increased by 14 percent in 2004, this was offset by wider AECO differentials from NYMEX combined with the appreciation of the U.S./Canadian dollar exchange rate. Natural gas prices had rebounded in 2003 from weaker prices experienced in 2002 due to continuing concerns about overall North American storage levels and a lack of confidence concerning prospects for North American supply growth. The average AECO daily spot price in 2003 was 64 percent above the 2002 average.

Crude oil

The prices received for the crude oil sold by Blue Mountain are related to the price of crude oil in world markets. Prices for heavy crude oil and other lesser quality crudes trade at a discount (or differential) to light crude oil.

The average West Texas Intermediate ("WTI") price increased by 33 percent in 2004 compared to 2003. This was caused by continued world oil demand strength, primarily in Asia and North America and, during the fourth quarter, concerns over winter heating oil supplies in North America. OPEC's reaction to high prices resulted in an increase in production over the course of the year. However, the incremental production was a heavier and more sour blend of crude oil than WTI and put added pressure on light to heavy oil price differentials. This follows a 19 percent increase in 2003, which was due in large part to supply disruptions in Venezuela and Nigeria as well as uncertainty preceding the invasion of Iraq. The slow return of Iraqi oil production and OPEC's successful production management, combined with strong Asian demand, kept crude oil inventories low with resulting upward pressure on prices in 2003.

This increases in the WTI price were not entirely reflected in Canadian pricing, however, as the strengthening Canadian dollar reduced the 2004 increase in the Edmonton Par price to 25 percent and the 2003 increase in the Edmonton Par price to 8 percent.

As noted above, Canadian heavy oil differentials increased in 2004 due to an increased supply of heavy oil placed into the market by OPEC. In 2003, Canadian heavy oil differentials widened in absolute terms compared to 2002, but the widening was primarily due to the higher average price for Edmonton Par. Actual average prices for heavy oil varied little from 2002 to 2003.

Foreign exchange risk

Blue Mountain's results are affected by the exchange rate between the Canadian and U.S. dollars. The majority of the Company's revenues are received from the sale of oil and natural gas commodities that receive prices determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and natural gas commodities and correspondingly, an increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Blue Mountain's expenditures are in Canadian dollars.

As the U.S. dollar continued to weaken in 2004, the average U.S./Canadian dollar exchange rate increased by 7 percent, after increasing by 13 percent in 2003. The increases are primarily due to continuing differences between Canadian and U.S. interest rates and the U.S. current account deficit.

Operational risk

Exploration risk arising from the uncertainty of finding new reserves is mitigated by employing highly competent professionals and providing them with leading-edge technology. A careful risk/reward analysis is carried out in advance of every project, and the Company reduces its capital exposure on high risk ventures by seeking promotional opportunities and joint ventures with industry partners. The Company maintains comprehensive insurance coverage on its assets and operations.

Regulatory risk

The operations of all oil and natural gas explorers and producers are subject to extensive controls and regulations imposed by various levels of government. Blue Mountain monitors and adheres to all regulations which could affect its operations and has established standards of operating practice which are designed to minimize risk to our employees, the community and the environment. Similar to other companies in the oil and natural gas industry, Blue Mountain incurs costs for preventive and corrective actions. Changes to regulations could have an adverse effect on the Company's results of operations and financial condition.

The Kyoto protocol, ratified by the Canadian federal government in December 2002, came into force on February 16, 2005. The protocol commits Canada to reducing greenhouse gas emissions to six percent below 1990 levels over the period 2008 to 2012. It is expected that the federal government will make a substantive announcement outlining its Climate Change action plan coinciding with Kyoto coming into force. The Climate Change Working Group of the Canadian Association of Petroleum Producers is working with the federal and Alberta governments to develop an approach for implementing targets and enabling greenhouse gas control legislation which protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector. As the federal government has yet to release its Kyoto compliance plan, Blue Mountain is unable to predict the impact of the potential regulations upon its business; however, it is possible that the Company would face increases in operating costs in order to comply with greenhouse gas emissions legislation.

Sensitivity analysis

The following table is indicative of the relative effect on net earnings and cash flow of changes in certain key variables. The analysis is based on business conditions and production volumes forecast for 2005. Each item in the sensitivity analysis projects the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or under greater magnitudes of change.

		Effect on Cash Flow		Effect on Earnings	
Variable	Increase	($000s)	($/share)	($000s)	($/share)
WTI crude oil price	US$1.00/bbl	346	0.02	212	0.01
AECO natural gas price	Cdn$0.10/mcf	491	0.02	304	0.01
US$/Cdn$ exchange rate	US$0.01	(137)	–	(84)	(0.01)
Canadian prime interest rate	1.0 percent	(74)	–	(46)	–

Management strategy

Blue Mountain will continue to execute its long-term business plan, which is expected to increase reserves and production in the Western Canada Sedimentary Basin through effective exploration and development programs and selective acquisitions.

Blue Mountain's capital investment program is principally focused on growing reserves and production in the Peace River Arch and West Central areas of Alberta, and in Northeast British Columbia, which typically offer multi-zone potential and high quality, long life reserves. For 2005, the Company has budgeted $40.0 million, which includes $34.3 million in internally generated exploration and development portfolio expenditures and $5.0 million allocated to acquisitions. Blue Mountain continuously evaluates asset and corporate acquisition candidates, and executes those that are economically viable and strategically beneficial. The 2005 budget includes costs of drilling approximately 40 to 45 wells, related equipment purchases and facilities construction, and undeveloped land and geophysical data acquisitions.

For budgetary and planning purposes, Blue Mountain has forecast average 2005 commodity prices of US$40.00 per barrel of WTI crude oil, $7.04 per mcf of natural gas at AECO, and a US$/Cdn$ exchange rate of $0.80.

Results of operations

Sales volumes

In 2004, Blue Mountain's total sales volumes increased by 107 percent, to an average of 2,281 boe per day, from 1,101 boe per day in 2003.

Sales volumes in the fourth quarter of 2004 averaged 2,693 boe per day, an increase of 44 percent from 1,867 boe in the fourth quarter of 2003. The increase is attributable primarily to producing properties acquired in the Sentra transaction which closed at the end of the third quarter.

In 2004, natural gas sales averaged 8.3 mmcf per day compared to 3.3 mmcf per day in 2003, an increase of 154 percent. Natural gas sales averaged 9.6 mmcf per day in the fourth quarter of 2004, an increase of 44 percent from 6.7 mmcf per day in the fourth quarter of 2003. The increase resulted mainly from additional production acquired in the Sentra transaction, new production on-stream at Spirit River and Mirage in the Peace River Arch, which was offset slightly by production declines at Dunvegan, and new production on-stream at Westerose in West Central Alberta.

Sales of crude oil increased by 43 percent in 2004 to average 704 barrels per day from 491 barrels per day in 2003. In the fourth quarter of 2004, crude oil sales averaged 883 barrels per day, up by 50 percent from 588 barrels per day in the fourth quarter of 2003. The increase is mainly the result of and new production at Brazeau in West Central Alberta, at Worsley in the Peace River Arch and the addition of Sentra producing properties.

Natural gas liquids ("NGLs") sales increased by 198 percent in 2004, to an average of 194 barrels per day from 65 barrels per day in 2003. NGL sales averaged 211 barrels per day in the fourth quarter of 2004 compared to 169 barrels per day during the same period in 2003, an increase of 25 percent. The increase is the result of higher liquids-rich natural gas production.

The following table provides a comparative summary of sales volumes for 2004 and 2003:

	Natural Gas (mcf per day)				Crude Oil and NGLs (bbls per day)				Combined Average (boe per day)			
	Q4		Year		Q4		Year		Q4		Year	
	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003
West Central Alberta	4,118	3,522	3,798	2,342	309	91	186	50	995	678	819	440
Peace River Arch Alberta	4,423	3,088	4,162	866	125	97	118	29	862	612	812	173
Southern Alberta	70	50	90	63	38	33	56	28	50	41	71	39
Saskatchewan	–	–	–	–	520	536	512	449	520	536	512	449
Northeast British Columbia	983	–	247	–	102	–	26	–	266	–	67	–
Total	9,594	6,660	8,297	3,271	1,094	757	898	556	2,693	1,867	2,281	1,101

The corporate 2004 exit production rate was 2,675 boe per day, reflecting production increases from drilling and the acquisition of Sentra. Previously anticipated exit production rates were heavily reliant on third party construction of a line-loop at Spirit River in the Peace River Arch. Unfortunately, delays occurred and this line wasn't completed until late February of 2005, leaving over 1,000 boe per day behind pipe over year-end.

In the first quarter of 2005, production is expected to average 2,800 boe per day, and the corporate exit production rate at the end of March 2005 is anticipated to be 3,500 boe per day. Production should reach approximately 3,850 boe per day in mid-April, when the remaining greater Spirit River area production comes on-stream with the completion of compressor modifications at Mirage.

Revenues

Gross sales revenues in 2004 were $33.1 million, an increase of 147 percent from $13.4 million in 2003. In the fourth quarter of 2004, gross sales revenues increased by 92 percent to $10.5 million from $5.4 million during the same period in 2003. The increase in sales revenues is primarily the result of increased sales volumes and higher commodity prices.

The following table provides a comparative summary of revenues for 2004 and 2003:

	Q4			Year		
($000s)	2004	2003	Change	2004	2003	Change
Natural gas	6,381	3,777	69%	21,086	7,852	169%
Crude oil	3,124	1,199	161%	9,295	4,835	92%
NGLs	952	459	107%	2,745	717	283%
Total sales revenues	10,457	5,435	92%	33,126	13,404	147%
Interest income	–	31	(100%)	63	292	(78%)
Total revenues	10,457	5,466	91%	33,189	13,696	142%

Commodity prices

Blue Mountain's wellhead price for crude oil averaged Cdn$36.22 per barrel in 2004. Average 2004 oil prices for WTI and Edmonton par were US$41.42 and Cdn$52.91, respectively. The differential reflects the components of Blue Mountain's 2004 oil production, which include Lloydminster heavy and southwest Saskatchewan medium-gravity crude.

Blue Mountain's average sales price for natural gas was $6.94 per mcf in 2004. The Alberta daily spot price at AECO in 2004 averaged $6.87 per mcf. The difference represents favorable heat content variations.

Blue Mountain's wellhead price for NGLs averaged $38.69 per barrel in 2004, a result of higher oil prices during the year. Condensate prices in particular are highly correlated to oil prices.

The following table provides a comparative summary of Blue Mountain's sales prices for 2004 and 2003:

	Q4			Year		
Commodity	2004	2003	Change	2004	2003	Change
Natural gas ($/mcf)	7.23	6.16	17%	6.94	6.58	5%
Crude oil ($/bbl)	38.48	22.89	68%	36.22	27.67	31%
NGLs ($/bbl)	49.02	29.42	67%	38.69	30.45	27%
Combined average ($/boe)	42.21	31.86	32%	[illegible]	33.67	18%

Expenses

Royalties

Royalties, net of the Alberta Royalty Tax Credit, totaled $6.8 million in 2004 (2003 – $2.0 million). Royalties as a percentage of total sales averaged 20.4 percent for the year (2003 – 15.4 percent) and 20.2 percent in the fourth quarter (2003 – 16.4 percent). In 2004, the royalty rate on oil production averaged 17 percent, the natural gas royalty rate averaged 21 percent and the royalty rate for NGLs averaged 29 percent of revenues. The 2004 average royalty rate increase from 2003 was a result of higher Crown royalty production brought on-stream, expiration of oil royalty holidays and the diminishing effect of the maximum $0.5 million Alberta Royalty Tax Credit on increasing revenues and royalties.

The following table provides a comparative summary of Blue Mountain's royalty rates as a percentage of revenue for 2004 and 2003:

	Q4			Year		
Commodity	2004	2003	Change	2004	2003	Change
Natural gas	21%	17%	24%	21%	16%	31%
Crude oil	15%	9%	67%	17%	12%	42%
NGLs	30%	30%	0%	29%	29%	0%
Combined boe average	20%	16%	23%	20%	15%	32%

Operating expenses

Operating expenses in 2004 totaled $7.0 million or $8.39 per boe of production, compared to $3.1 million or $7.76 per boe of production in 2003. The increase in unit operating expenses over 2003 reflects a general industry-wide trend, in addition to increased well servicing and lease rental costs throughout the year. Fourth quarter 2004 operating costs averaged $9.10 per boe, an increase of 44 percent from the same period in 2003. The fourth quarter increase is mainly attributable to well servicing at Spirit River and at Brazeau, rising costs per boe at Dunvegan due to production declines and higher operating costs per boe at acquired Sentra properties.

The following table provides a comparative summary of Blue Mountain's average unit operating expenses for 2004 and 2003:

	Q4			Year		
Commodity	2004	2003	Change	2004	2003	Change
Natural gas ($/mcf)	1.48	0.83	78%	1.16	0.91	27%
Crude oil ($/bbl)	9.52	9.29	2%	11.61	10.66	9%
NGLs ($/bbl)	8.89	4.98	79%	6.95	5.43	28%
Combined average ($/boe)	9.10	6.34	44%	8.39	7.76	8%

The Company is continually evaluating operating cost efficiency opportunities and believes that as lower cost natural gas production is brought on-stream, operating expenses will decrease.

Transportation expenses

Transportation expenses, composed of costs to transport sales gas and clean oil to market, totalled $0.8 million in 2004 (2003 – $0.2 million), or $0.99 per boe (2003 – $0.44 per boe). In the fourth quarter of 2004, transportation expenses totalled $0.3 million (2003 – $0.1 million). Transportation expenses have increased as a direct result of increased natural gas production.

General and administrative expenses

General and administrative ("G&A") expenses were $1.7 million or $2.00 per boe of production in 2004, compared to $1.1 million or $2.69 per boe of production in 2003. Capitalized G&A costs related to exploration activity in 2004 amounted to $0.7 million. Blue Mountain capitalized $0.5 million in G&A costs relating to exploration activity in 2003.

The following table provides a comparative summary of G&A expenses for 2004 and 2003:

	2004		2003	
	$000s	$/boe	$000s	$/boe
Gross G&A expenses	2,403	2.88	1,570	3.91
Capitalized G&A expenses	(731)	(0.88)	(488)	(1.22)
Total G&A expenses	1,672	2.00	1,082	2.69
Non-cash G&A expenses – compensation costs	(426)	(0.51)	(190)	(0.47)
Net cash G&A expenses	1,246	1.49	892	2.22

General and administrative expenses on a per unit basis are expected to continue to decrease as production volumes increase.

Depletion, depreciation and accretion

Depletion and depreciation of property, plant and equipment, including asset retirement costs, and accretion of asset retirement obligations was $14.0 million in 2004 (2003 – $5.1 million) or $16.76 per boe of production (2003 – $12.63 per boe). The increase on a unit-of-production basis is due to higher finding and development costs for proved reserves in 2004. Depletion is calculated on proved reserves only.

Income and other taxes

Future income tax expense was $1.1 million in 2004 (2003 – $0.4 million). Future income tax expense in 2003 included a reduction of $0.4 million as a result of a reduction in both Canadian federal and Alberta corporate tax rates. For a more detailed analysis of the components of both future tax expense and the balance sheet provision for future income taxes, refer to note 8 of the consolidated financial statements for the years ended December 31, 2004 and 2003.

Capital tax expense of $0.3 million in 2004 (2003 – $0.2 million) reflects federal capital taxes payable at the rate of 0.2 percent on taxable capital in excess of $50 million and Saskatchewan resource surcharges at the rate of 3.6 percent on revenue generated in that province.

At year-end 2004, the Company had unused tax pools totaling $97.6 million, which may be used to offset future income tax liabilities.

The following table provides a comparative summary of the composition of the Company's tax pools for 2004 and 2003:

At December 31 ($000s)	2004	2003
Canadian exploration expense	15,146	4,951
Canadian development expense	20,221	3,545
Canadian oil and gas property expense	32,154	11,542
Undepreciated capital cost	24,055	6,263
Operating losses	2,451	1,441
Capital losses	1,254	1,254
Share issue costs and other	2,315	1,451
Total	97,596	30,447

Cash flow and earnings

Cash flow from operations increased to $16.8 million in 2003 from $7.3 million in 2003. Cash flow was $1.09 per share basic ($1.03 per share diluted) in 2004, compared to $0.58 per share basic ($0.55 per share diluted) in 2003.

Blue Mountain's earnings decreased to $1.4 million in 2004 from $1.6 million in 2003, primarily due to the reduction in future income tax expense in 2003 as described above. Earnings per share were $0.09 basic and diluted in 2004, compared to $0.13 per share basic ($0.12 per share diluted) in 2003. Higher depletion expense in the fourth quarter of 2004 resulted in a loss for the period.

The increase in cash flow in 2004 was due primarily to higher production and sales volumes, aided by higher commodity prices.

The following table provides a comparative summary of Blue Mountain's cash flow from operations and earnings for 2004 and 2003:

(000s, except per share amounts)

	Q4			Year		
	2004	2003	Change	2004	2003	Change
Cash flow from operations	5,056	3,034	67%	16,830	7,250	132%
per share – basic	0.26	0.24	8%	1.09	0.58	88%
per share – diluted	0.25	0.22	14%	1.03	0.55	87%
Earnings	(627)	210	(399%)	1,327	1,602	(17%)
per share – basic	(0.04)	0.02	(300%)	0.09	0.13	(31%)
per share – diluted	(0.04)	0.02	(300%)	0.08	0.12	(33%)

Netbacks

Blue Mountain's operating netback averaged $22.20 per boe of production in 2004 (2003 – $20.07 per boe). The Company's cash flow netback, after adding interest revenue and deducting cash G&A expenses, interest expense and capital tax expense, averaged $20.19 per boe of production in 2004 (2003 – $18.08 per boe).

The following table provides a comparative summary of Blue Mountain's netbacks per unit of production for 2004 and 2003:

	2004	2003
Crude oil ($/bbl)		
Average sales price	[illegible]	27.67
Hedging adjustment	[illegible]	(0.70)
Royalties	[illegible]	(3.27)
Operating costs	[illegible]	(10.66)
Transportation	[illegible]	(0.36)
Netback	[illegible]	12.68
Natural gas ($/mcf)		
Average sales price	[illegible]	6.58
Royalties	[illegible]	(1.04)
Operating costs	[illegible]	(0.91)
Transportation	[illegible]	(0.10)
Netback	[illegible]	4.53
NGLs ($/bbl)		
Average sales price	[illegible]	30.45
Royalties	[illegible]	(8.92)
Operating costs	[illegible]	(5.43)
Netback	[illegible]	16.10
BOE basis ($/boe)		
Average sales price	[illegible]	33.67
Hedging adjustment	(0.05)	(0.32)
Royalties	[illegible]	(5.08)
Operating costs	[illegible]	(7.76)
Transportation	[illegible]	(0.44)
Netback	22.20	20.07
Interest income	[illegible]	0.73
G&A expense – cash	[illegible]	(2.22)
Interest expense	[illegible]	–
Capital taxes	[illegible]	(0.50)
Cash flow	[illegible]	18.08
G&A expense – non-cash (stock-based compensation expense)	[illegible]	(0.47)
Depletion and depreciation	[illegible]	(12.55)
Accretion of asset retirement obligations	(0.10)	(0.08)
Future taxes	[illegible]	(0.99)
Net earnings	[illegible]	3.99

Capital investment and asset values

Capital expenditures

Net capital expenditures totaled $78.0 million in 2004 compared to $22.5 million in 2003. Blue Mountain acquired 19,463 net acres of undeveloped land for $4.5 million and spent $1.6 million on seismic activity in 2004. A total of $5.8 million was spent on production equipment and facilities, including compression, to equip and tie-in 15 wells. Of the total, approximately $1.6 million was spent on infrastructure at Spirit River. A total of $21.1 million was spent completing 32 wells, re-completing six wells and drilling 33 (25.2 net) new wells, resulting in nine (7.1 net) new oil wells and 16 (11.9 net) new gas wells.

Property acquisitions and dispositions

In February 2004, the Company completed the acquisition of producing assets and undeveloped land in the Peace River Arch at Mirage, located just north of and adjacent to Blue Mountain lands at Spirit River, for total consideration of $4.1 million.

In the third quarter of 2004, the Company disposed of minor properties at Grand Forks and Hays in Southern Alberta for proceeds of $0.3 million.

Corporate acquisitions

In September 2004, Blue Mountain acquired all of the outstanding shares of Sentra Resources Corporation, an oil and gas exploration and production company with assets in close proximity to existing Blue Mountain assets, for consideration of $36.6 million in a share-exchange business combination. The oil and gas assets of Sentra were recorded at their fair market value of $40.0 million, including $10.0 million in undeveloped land.

The following table provides a comparative summary of Blue Mountain's capital expenditures in 2004 and 2003:

($000s)	2004	2003
Land acquisition and retention	4,765	2,956
Geological and geophysical	1,560	910
Drilling and completions	21,136	6,844
Production equipment and facilities	5,834	3,181
Capitalized overhead	731	488
Corporate assets	145	107
Property acquisitions	4,105	7,999
Acquisition of Sentra Resources Corporation	40,000	–
Total capital expenditures	78,276	22,485
Property dispositions	(287)	–
Net capital expenditures	77,989	22,485

Drilling activity

2004

	Exploration		Development		Total	
Number of Wells	Gross	Net	Gross	Net	Gross	Net
Oil	3.0	2.8	6.0	6.0	9.0	[illegible]
Natural gas	10.0	9.9	6.0	4.9	[illegible]	11.1
Unsuccessful	8.0	6.2	–	–	8.0	[illegible]
Total	21.0	15.7	12.0	9.8	[illegible]	24.1

2003

	Exploration		Development		Total	
Number of Wells	Gross	Net	Gross	Net	Gross	Net
Oil	1.0	0.7	2.0	1.0	3.0	1.7
Natural gas	6.0	2.3	8.0	3.1	14.0	5.4
Unsuccessful	3.0	1.3	5.0	2.9	8.0	4.2
Total	10.0	4.3	15.0	7.0	25.0	11.3

Land holdings

In 2004 Blue Mountain increased its net undeveloped land position by 136 percent, through a combination of Crown sales and the acquisition of Sentra. Blue Mountain's average working interest decreased slightly to 72 percent (2003 – 74 percent), as undeveloped lands in British Columbia acquired in the Sentra acquisition are, on average, at lower working interests. At year-end 2004, the Company's undeveloped land position stood at 140,370 net acres compared to 59,564 net acres in 2003. Blue Mountain's land position is a key asset in generating internal growth.

At December 31, 2004	Undeveloped		Developed		Total	
(acres)	Gross	Net	Gross	Net	Gross	Net
Alberta	162,765	124,542	58,391	3,634	221,156	128,176
British Columbia	27,147	1,467	10,028	6,032	37,175	7,499
Saskatchewan	5,868	4,361	880	672	6,748	5,033
	195,780	140,370	69,299	10,338	265,079	150,708

Reserves

The December 31, 2004 reserve report was prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") and utilized definitions as set out under National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

Blue Mountain's reserve estimates have been calculated in compliance with the NI 51-101 standards as first implemented for last year's reserve evaluation. This standard requires a mandated high confidence for proved and probable reserves. Under NI 51-101, proved reserves are defined as having a 90 percent probability that actual

reserves recovered over time will equal or exceed proved reserve estimates. For probable reserves under NI 51-101, there is now equal (50 percent) probabilities the actual reserves recovered will be less than or greater than the proved plus probable reserve estimate.

In accordance with NI 51-101, proved undeveloped and proved non-producing reserves are only to be recognized in cases where plans are in place to bring the reserves on to production within a short and well defined time frame. It should be noted that the Company does not carry any proved undeveloped reserves and approximately 85 percent of the Company's proved non-producing reserves are either already tied-in or are proposed to be tied-in during 2005.

In 2004, Blue Mountain added new reserves through the drill bit totalling 0.7 million boe proved (1.2 million boe proved plus probable). Acquisitions added additional reserves of 1.4 million boe proved (2.2 million boe proved plus probable).

At December 31, 2004, net proved reserves as determined by McDaniel were 3.8 million boe and proved plus probable reserves were 6.1 million boe. Utilizing the production profiles in the McDaniel reserve report, the Company's reserve life index is calculated to be 4.5 years proved plus probable and 3.1 years proved, based on a 2005 forecasted average production rate of 3,743 boe per day and 3,373 boe per day, respectively.

The reserves information in the following tables is extracted from McDaniel's evaluations based on forecast prices and costs:

Summary of reserves At December 31, 2004	Crude Oil (mbbls)	NGLs (mbbls)	Natural Gas (mmcf)	Total mboe @ 6:1	NPV @ 10% before Tax ($000s)	NPV @ 15% before Tax ($000s)
Proved producing	782	178	10,789	2,758	42,055	38,772
Proved non-producing	57	85	5,304	1,026	16,647	15,391
Proved undeveloped	–	–	–	–	–	–
Total proved	839	263	16,093	3,784	58,702	54,163
Probable additional	636	140	9,200	2,309	27,109	22,641
Proved + probable	1,475	403	25,293	6,093	85,811	76,804

	Crude Oil (mbbls)			NGLs (mbbls)			Natural Gas (mmcf)			Boe		
Reserve reconciliation	Prov.	Prob.	Total	Prov.	Prob.	Total	Prov.	Prob.	Total	Prov.	Prob.	Total
Reserves at December 31, 2003	470	335	805	160	77	237	10,924	5,824	16,748	2,451	1,382	3,833
Discoveries	140	83	223	50	23	73	3,306	2,072	5,378	741	451	1,192
Acquisitions	355	234	589	97	48	145	5,769	2,979	8,748	1,413	779	2,192
Dispositions	(24)	(5)	(29)	–	–	–	(21)	(1)	(22)	(28)	(5)	(33)
Revisions	156	(11)	145	27	(8)	19	(848)	(1,674)	(2,522)	42	(298)	(256)
Production	(258)	–	(258)	(71)	–	(71)	(3,037)	–	(3,037)	(835)	–	(835)
Reserves at December 31, 2004	**839**	**636**	**1,475**	**263**	**140**	**403**	**16,093**	**9,200**	**25,293**	**3,784**	**2,309**	**6,093**

Value of reserves As at December 31, 2004 ($000s before tax)	Undiscounted	Discounted 5%	 10%	 15%
Proved	69,505	62,398	56,941	52,584
Probable	42,812	32,747	26,432	22,122
	112,317	95,145	83,373	74,706
Alberta Royalty Tax Credit	3,666	2,922	2,438	2,098
Total	115,983	98,067	85,811	76,804

Pricing assumptions	WTI Oil US$/bbl	AECO Gas Cdn$/mcf	US$/Cdn$ Exchange	Inflation %
2005	42.00	6.80	0.83	2.0
2006	39.50	6.54	0.83	2.0
2007	37.00	6.38	0.83	2.0
2008	35.00	6.12	0.83	2.0
2009	34.50	6.01	0.83	2.0

Finding, development and acquisition ("FD&A") costs

In 2004, Blue Mountain's average FD&A costs to add and bring on-stream new reserves were $25.81 per boe proved plus probable and $36.48 per boe proved. These calculations include technical revisions, an increase in future development capital of $1.7 million and capitalized G&A costs of $0.7 million. Blue Mountain's calculated FD&A costs before consideration of NI 51-101-mandated technical revisions and future development capital were $23.27 per boe proved plus probable and $36.65 per boe proved.

The Company commenced operations in July 2002. For the three-year period since inception Blue Mountain has recorded a weighted average FD&A cost of $14.92 per boe proved plus probable and $22.55 per boe proved.

The following tables provide a comparative analysis of the Company's FD&A costs for 2004, 2003 and 2002:

Capital costs ($000s)	2004	2003	2002
Finding and development expenditures	34,171	14,486	4,225
Acquisition expenditures	43,818	7,999	15,599
Net capital expenditures	77,989	22,485	19,824
Change from previous year's estimated future development capital for:			
Proved reserves found	1,513	1,216	428
Probable reserves found	(577)	203	153
Proved reserves acquired	(301)	371	270
Probable reserves acquired	1,310	(119)	(124)
Total estimated capital for FD&A costs	79,934	24,156	20,551

Reserve additions	2004	2003	2002
Proved reserve additions (mboe)			
Reserve discoveries and extensions, including revisions	785	775	640
Reserves acquired, net of dispositions	1,386	475	1,083
Total proved	2,171	1,250	1,723
Probable reserve additions (mboe)			
Reserve discoveries and extensions, including revisions	153	670	435
Reserves acquired, net of dispositions	773	310	370
Total probable	927	980	805
Proved + probable reserve additions (mboe)			
Reserve discoveries and extensions, including revisions	938	1,445	1,075
Reserves acquired, net of dispositions	2,159	785	1,453
Total proved + probable	3,098	2,230	2,528

FD&A costs	Three year average	2004	2003	2002
Proved FD&A costs ($/boe)				
Reserve discoveries and extensions including revisions	24.33	45.47	20.26	7.27
Reserves acquired, net of dispositions	21.22	31.60	17.62	14.65
Total proved	22.55	36.48	19.26	11.91
Proved + probable FD&A costs ($/boe)				
Reserve discoveries and extensions, including revisions	17.63	37.42	11.01	4.47
Reserves acquired, net of dispositions	14.04	20.76	10.51	10.84
Total proved + probable	14.92	25.01	10.83	8.13
Recycle ratio [1]				
Proved	1.06	0.61	1.04	1.54
Proved + probable	1.66	0.84	1.85	2.26

[1] Operating netback divided by finding and on-stream costs

Asset valuation

The estimated present value of Blue Mountain's proved plus probable reserves is based on an evaluation conducted by McDaniel. The value of reserves represents the forecast of future net cash flow derived from the production and sale of reserves, less capital expenditures, abandonment costs and operating costs, before the deduction of interest, income tax, and other corporate costs. The net present value, discounted at 10 percent, of estimated future revenues for proved plus probable reserves was $85.8 million at December 31, 2004. Seismic data is assigned its estimated fair market value and undeveloped land is valued at $150 per acre, which the Company believes is a conservative estimate of fair market value. Blue Mountain's actual average undeveloped land acquisition cost was $227 per acre in 2004 (2003 – $179 per acre).

On a fully diluted basis, Blue Mountain's year-end 2004 asset value increased by $41.6 million or 60 percent, and net asset value per share increased by $0.53 or 13 percent, over year-end 2003.

At year-end 2004, basic asset value increased by $41.2 million or 69 percent from year-end 2003, and net asset value per share basic increased by $0.52 or 12 percent.

Net asset value ($000s)	2004	2003	2002
Proved plus probable reserve value, 10% discounted before tax[1]	85,811	43,333	24,177
Seismic data value	5,492	755	331
Undeveloped acreage value	21,055	7,445	3,472
Working capital surplus (deficiency)	(11,440)	8,208	14,726
Basic asset value	100,919	59,741	42,706
Exercise of in-the-money warrants	1,650	5,713	–
Exercise of in-the-money stock options	8,964	4,155	3,231
Diluted asset value	111,533	69,609	45,937
Common shares outstanding	21,261,993	14,106,750	12,503,040
In-the-money warrants outstanding	459,908	1,154,333	–
In-the-money options outstanding	1,890,461	1,341,295	1,180,733
Diluted	23,612,362	16,602,378	13,683,773
Net asset value per common share ($)			
Basic	4.75	4.23	3.42
Diluted	4.72	4.19	3.36

(1) 2002 present value is based on McDaniel's established reserves (proved plus 50 percent probable).

Quarterly financial summary

2004	Quarter ended March 31	Quarter ended June 30	Quarter ended Sept. 30	Quarter ended Dec. 31
Total revenues, net of royalties ($000s)	7,068	6,309	5,703	8,266
Net earnings (loss) ($000s)	951	644	445	(627)
Per share – basic ($)	0.06	0.04	0.03	(0.04)
Per share – diluted ($)	0.06	0.04	0.03	(0.04)
Cash flow from operations ($000s)	4,985	3,318	3,479	5,056
Per share – basic ($)	0.35	0.24	0.24	0.26
Per share – diluted ($)	0.33	0.22	0.23	0.25
Share price ($)				
High	6.95	9.00	8.10	9.45
Low	6.00	6.10	7.00	7.51
Close (end of period)	6.40	8.09	7.59	8.10
Shares traded (000s)	1,801	1,477	1,575	2,489
Weighted average number of shares (000s)				
Basic	14,112	14,159	14,256	19,452
Diluted	15,069	15,035	15,294	20,394

Blue Mountain's revenues, cash flow and earnings were higher in the first quarter of 2004 as natural gas production at Dunvegan was increased to take advantage of higher prices in January. In the fourth quarter, revenues and cash flow rose again, primarily due to increased production resulting from the acquisition of Sentra. The Company recorded a net loss in the fourth quarter of 2004, as earnings were reduced by an after-tax increase to depletion expense of $1.4 million based on the December 31, 2004 reserve report.

Quarterly financial summary

2003	Quarter ended March 31	Quarter ended June 30	Quarter ended Sept. 30	Quarter ended Dec. 31
Total revenues, net of royalties ($000s)	2,156	2,141	2,769	4,588
Net earnings ($000s)	341	763	288	210
Per share – basic ($)	0.03	0.06	0.02	0.02
Per share – diluted ($)	0.02	0.06	0.02	0.02
Cash flow from operations ($000s)	1,364	1,245	1,607	3,034
Per share – basic ($)	0.11	0.10	0.13	0.24
Per share – diluted ($)	0.11	0.10	0.12	0.22
Share price ($)				
High	4.35	4.55	7.25	7.20
Low	3.15	3.25	3.95	5.00
Close (end of period)	3.55	4.10	7.01	6.39
Shares traded (000s)	1,688	2,628	2,699	1,304
Weighted average number of shares (000s)				
Basic	12,503	12,503	12,540	12,801
Diluted	12,830	12,913	13,201	13,721

Blue Mountain's revenue and cash flow increased in the third and fourth quarters of 2003 as new production came on-stream. Earnings in the second quarter included a reduction to future tax expense in the amount of $0.4 million resulting from a reduction in the Canadian federal and Alberta corporate tax rates. Earnings in the fourth quarter were reduced by an after-tax increase to depletion expense of $0.5 million based on the December 31, 2003 reserve report.

Liquidity and capital resources

Working capital

The working capital deficiency, exclusive of bank debt, at December 31, 2004 was $7.4 million, compared to a working capital surplus of $8.2 million at December 31, 2003. The change is due to two factors. With the acquisition of Sentra in 2004 through a share-exchange business combination, the Company assumed Sentra's debt and working capital deficiency. As well, working capital in excess of cash flow from operations was invested in exploration and development projects during 2004.

Bank debt

The Company had drawn $4.0 million against its credit facility at December 31, 2004 (2003 – nil). The Company's credit facility, negotiated in 2004, is with a Canadian chartered bank in the form of a $24.0 million revolving demand loan and bears interest at the bank's prime lending rate. The loan is secured by all of the Company's assets with a general security agreement. Based on 2005 budget projections, Blue Mountain anticipates that it will utilize additional debt to finance a portion of its capital expenditure program in 2005.

Capital structure

In 2004, Blue Mountain completed a private placement consisting of 1,000,000 common shares at $8.25 per share and 500,000 flow-through shares at a price of $10.60 per share for gross proceeds of $13.6 million.

The Company had 21,261,993 common shares outstanding at December 31, 2004. Based on a year-end closing price of $8.10 per share, Blue Mountain's market capitalization was $172.2 million. A total of 7,640,600 shares traded during the year, representing 36 percent of the total shares outstanding.

Capital expenditure program

Blue Mountain's 2005 budget includes $40.0 million in capital expenditures directed at exploration and development projects and selective acquisitions.

The capital expenditure program will be financed with working capital, cash flow and bank debt. The Company expects to exit 2005 with a debt:cash flow ratio of approximately 0.7:1, based on an annualized fourth quarter 2005 cash flow estimate.

In the event of significantly lower cash flow, the Company would be able to defer its capital spending programs without penalty.

Contractual obligations

The Company has entered into commitments related to office leases. The following table summarizes the Company's contractual obligations at December 31, 2004:

	Expected Payment Date				
($000s)	2005	2006	2007	2008	Total
Office leases	357	302	302	75	1,036

Off-balance-sheet arrangements

Blue Mountain does not currently utilize any off-balance-sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions or for any other purpose.

Related party transactions

Blue Mountain has not entered into any material transactions with related parties in 2004 or 2003.

Financial and derivative instruments

The Company periodically enters into oil and natural gas pricing agreements to provide it with exposure to a variety of pricing indices. At December 31, 2004, there were no oil and natural gas pricing agreements in place.

Application of critical accounting estimates

The significant accounting policies used by Blue Mountain Energy Ltd. are disclosed in note 1 to the consolidated financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discusses such accounting policies and is included in the MD&A to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially

different results being reported. Blue Mountain's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

The following assessment of significant accounting policies is not meant to be exhaustive. The Company might realize different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

Proved oil and natural gas reserves

Under NI 51-101, proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable (it is likely that the actual remaining quantities recovered will exceed the estimated proved reserves). In accordance with this definition, the level of certainty targeted by the reporting company should result in at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated reserves. There was no such consideration of probability under the previous standard for reporting reserves, known as National Policy (NP) 2B. In the case of probable reserves, which are obviously less certain to be recovered than proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. With respect to the consideration of certainty, in order to report reserves as proved plus probable, the reporting company must believe that there is at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves. The implementation of NI 51-101 has resulted in a more rigorous and uniform standardization of reserve evaluation.

Full cost accounting for oil and gas activities

Depletion expense

The Company uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development, whether successful or not, are capitalized. The aggregate of net capitalized costs and estimated future development costs, less estimated salvage values, is amortized using the unit-of-production method based on estimated proved oil and natural gas reserves.

An increase in estimated proved oil and natural gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would also result in a corresponding reduction in depletion expense.

Withheld costs

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Impairment of long-lived assets

The Company is required to review the carrying value of all property, plant and equipment, including the carrying value of oil and natural gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and natural gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

Fair value of derivative instruments

Periodically Blue Mountain utilizes financial derivatives to manage market risk. The purpose of the hedge is to provide an element of stability to the Company's cash flow in a volatile environment. Blue Mountain discloses the estimated fair value of open hedging contracts as at the end of a reporting period. Effective January 1, 2004 the Company adopted CICA Accounting Guideline 13, "Hedging Relationships" ("AcG-13").

The estimation of the fair value of certain hedging derivatives requires considerable judgment. The estimation of the fair value of commodity price hedges requires sophisticated financial models that incorporate forward price and volatility data and, when compared with Blue Mountain's open hedging contracts, produce cash inflow or outflow variances over the contract period. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through quotes from financial institutions.

Asset retirement obligations

Effective January 1, 2004 the Company changed its accounting policy with respect to accounting for asset retirement obligations. CICA Section 3110 requires the fair value of asset retirement obligations to be recorded when they are incurred rather than merely accumulated or accrued over the useful life of the respective asset.

Legal, environmental remediation and other contingent matters

The Company is required to both determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined it is charged to earnings. The Company's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstance.

Income tax accounting

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Business combinations

Blue Mountain grew considerably when it acquired Bolt Energy Ltd. in September 2002 and again in September of 2004 with the acquisition of Sentra Resources Corporation. These transactions were accounted for using what is now the only accounting method available, the purchase method. Under the purchase method, the acquiring company includes the fair value of the assets of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. The valuation of oil and natural gas properties primarily relies on placing a value on the oil and natural gas reserves. The valuation of oil and natural gas reserves entails the process described above under the caption "Proved Oil and Natural Gas Reserves" but in contrast incorporates the use of economic forecasts that estimate future changes in prices and costs. In addition this methodology is used to value unproved oil and natural gas reserves. The valuation of these reserves, by their nature, is less certain than the valuation of proved reserves.

Goodwill

The process of accounting for the purchase of a company, described above, results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise, the determination of goodwill is also imprecise. In accordance with CICA section 3062, "Goodwill and Other Intangible Assets", goodwill is no longer amortized but assessed periodically for impairment. The process of assessing goodwill for impairment necessarily requires Blue Mountain to determine the fair value of its assets and liabilities. Such a process involves considerable judgment.

Accounting standards adopted in 2004

Asset retirement obligations

Effective January 1, 2004 this new method for accounting for asset retirement obligations requires an entity to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When initially recorded, the liability is added to the related property, plant and equipment, subsequently increasing depletion, depreciation and amortization expense. In addition, the liability is accreted for the change in present value in each period. The new Canadian standard is effective for fiscal years beginning on or after January 1, 2004. Upon adoption of CICA Section 3110, the Company will adjust its existing future removal and site restoration liability using the cumulative-effect approach.

The Company has estimated that the cumulative effect will be an increase of the future removal and site restoration liability of $0.7 million, an increase of related net property, plant and equipment of $0.8 million, an increase to the future income tax liability of $0.1 million and an increase in retained earnings of $0.1 million.

Accounting for derivative instruments and hedging activities

In Canada the Accounting Standards Board ("AcSB") intends to bring Canadian accounting standards into line with those in the U.S. by a two-stage approach. The first stage is an amendment to AcG-13, "Hedging Relationships", which is effective January 1, 2004 and establishes criteria to be satisfied before hedge accounting may be applied. The second stage comprises three exposure drafts that were issued on March 31, 2003. The culmination of stage two is expected to complete the harmonization of the Canadian accounting for derivatives, for all intents and purposes, with U.S. GAAP.

These accounting standards require that every derivative instrument, including certain derivative instruments embedded in other contracts, be recorded on the balance sheet as either an asset or liability measured at fair value. These standards further establish that changes in the fair value be recognized currently in earnings unless the arrangement can meet the "effective hedge" criteria.

Stock-based compensation plans

Effective January 1, 2004 CICA Section 3870, "Stock-based Compensation and Other Stock-based Payments", required all public companies to expense all stock-based compensation. This standard provides for the retroactive adoption of fair value accounting effective January 1, 2004. After January 1, 2004 the fair value of stock-based compensation and other transactions are recognized as an expense in the financial statements.

Oil and gas full cost accounting

In July 2003 the AcSB issued Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" ("AcG-16"), replacing AcG-5. AcG-16, provides for methodology consistent with CICA Section 3063, "Impairment of Long-lived Assets", and CICA Section 3475, "Disposal of Long-lived Assets and Discontinued Operations".

The new standards prescribe the recognition of impairment only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and measure the impairment amount as the difference between the carrying amount and the fair value. In addition, discontinued operations disclosure will be required upon the disposition of a component or cost centre of the entity rather than an entire business segment.

Continuous disclosure obligations

Effective March 31, 2004 the Company and all reporting issuers in Canada became subject to new disclosure requirements as per National Instrument 51-102 "Continuous Disclosure Obligations". TSX Venture issuers are exempt from certain of these requirements. This new instrument is effective for fiscal years beginning on or after January 1, 2004. The instrument proposes shorter reporting periods for filing of annual and interim financial statements, MD&A and the Annual Information Form ("AIF"). The instrument also proposes enhanced disclosure in the annual and interim financial statements, MD&A and AIF. Under this new instrument, it will no longer be mandatory for the Company to mail annual and interim financial statements and MD&A to shareholders, but rather these documents will be provided on an "as requested" basis. All relevant documents will continue to be available on the SEDAR website as currently required. As well, it is Blue Mountain's intention to make these documents available on the Company's website on a continuous basis.

Note regarding forward-looking statements

Certain information regarding Blue Mountain Energy Ltd. set forth in this document, including management's assessment of Blue Mountain Energy Ltd.'s future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond Blue Mountain Energy Ltd.'s control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and ability to access capital from internal and external sources. Blue Mountain Energy Ltd.'s actual results, performance or achievement could differ materially form those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Blue Mountain Energy Ltd. will derive therefrom. The Company undertakes no responsibility to update the information provided herein.

Management's report to the shareholders

All information presented in the Annual Report is the responsibility of the Company's management. The consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada and in accordance with accounting policies detailed in the notes to the financial statements. Where necessary, the statements include estimates based on management's objective and informed judgments. Management has prepared the financial information presented elsewhere in the Annual Report and has ensured that it is consistent with the financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Company's assets are safeguarded and that financial information is reliable and relevant.

The Audit Committee of the Board of Directors has reviewed the financial statements with management and KPMG LLP, the Company's external auditors. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Randy Pawliw

Randy Pawliw
President and Chief Executive Officer

Dale Joynt
Chief Financial Officer and Corporate Secretary

Calgary, Canada
March 22, 2005

Auditors' report to the directors

We have audited the consolidated balance sheets of Blue Mountain Energy Ltd. as at December 31, 2004 and 2003 and the consolidated statements of earnings and retained earnings (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 22, 2005

Consolidated balance sheets

As at December 31 ($ thousands)	2004	2003
		(Restated notes 1, 4)
Assets		
Current assets		
Cash and cash equivalents	–	9,687
Accounts receivable	12,370	6,642
	12,370	16,329
Property, plant and equipment (note 3)	102,031	37,485
Goodwill (note 2)	14,556	3,741
	128,957	57,555
Liabilities and shareholders' equity		
Current liabilities		
Accounts payable and accrued liabilities	19,781	8,121
Bank debt (note 6)	4,029	–
	23,810	8,121
Asset retirement obligations (note 4)	2,979	785
Future income taxes (note 8)	755	2,617
	27,544	11,523
Shareholders' equity		
Share capital (note 5)	97,421	43,808
Contributed surplus (note 7)	851	500
Retained earnings	3,141	1,724
	101,413	46,032
Commitments (note 11)		
Contingency (note 12)		
	128,957	57,555

See accompanying notes to the consolidated financial statements.

Approved by the Board,

Verne Johnson
Director

Randy Pawliw
Director

Consolidated statements of earnings and retained earnings (deficit)

For the year ended December 31

($ thousands except per share amounts)	2004	2003
		(Restated notes 1, 4)
Revenues		
Oil and gas sales	33,126	13,404
Royalties, net of Alberta Royalty Tax Credit	(6,765)	(2,042)
Interest income	63	292
	26,424	11,654
Expenses		
Operating	7,004	3,120
Transportation	830	179
General and administrative	1,672	1,082
Interest	173	–
Depletion and depreciation	13,908	5,040
Accretion of asset retirement obligations (note 4)	85	34
	23,672	9,455
Earnings before income and other taxes	2,752	2,199
Income and other taxes (note 8)		
Capital	320	202
Future	1,015	395
	1,335	597
Net earnings	1,417	1,602
Retained earnings (deficit), beginning of year, as reported	1,606	(4,057)
Elimination of deficit through reduction of share capital (note 5e)	–	4,057
Retroactive application of change in accounting policy (notes 1, 4)	118	122
Retained earnings beginning of year, as restated	1,724	122
Retained earnings, end of year	3,141	1,724
Weighted average number of shares outstanding (note 5g)		
Basic	15,506	12,587
Diluted	16,370	13,157
Basic earnings per share	0.09	0.13
Diluted earnings per share	0.09	0.12

See accompanying notes to the consolidated financial statements.

Consolidated statements of cash flow

For the year ended December 31 ($ thousands)	2004	2003
		(Restated notes 1, 4)
Cash provided by operating activities		
Net earnings	1,417	1,602
Add non-cash items		
Depletion and depreciation	13,908	5,040
Accretion of asset retirement obligations	85	34
Future income taxes	1,015	395
Stock-based compensation expense (note 7)	426	190
Abandonment expenditures	(13)	(11)
Funds from operations	16,838	7,250
Change in non-cash working capital items (note 10)	282	(1,752)
	17,120	5,498
Cash provided by financing activities		
Increase in bank debt, net	(8,213)	–
Issuance of common shares, net of issue costs	17,600	8,716
	9,387	8,716
Cash available for investing activities	26,507	14,214
Cash used in investing activities		
Business combination (note 2)	(997)	–
Additions to property, plant and equipment	(34,171)	(14,486)
Acquisitions – oil and gas properties	(4,105)	(7,999)
Dispositions – oil and gas properties	287	–
Change in non-cash working capital items (note 10)	2,792	(196)
	(36,194)	(22,681)
Decrease in cash and cash equivalents	(9,687)	(8,467)
Cash and cash equivalents, beginning of year	9,687	18,154
Cash and cash equivalents, end of year	–	9,687

See accompanying notes to the consolidated financial statements.

Notes to consolidated financial statements

Years ended December 31, 2004 and 2003

1. Significant accounting policies

Nature of business and basis of presentation

Blue Mountain Energy Ltd. (the "Company") is involved in the exploration, development and production of petroleum and natural gas in Alberta, Saskatchewan and British Columbia. The consolidated financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates. The financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the significant policies summarized below:

a) Principles of consolidation

The consolidated statements include the accounts of the Company and its subsidiaries, all of which are inactive.

b) Joint operations

Certain of the Company's petroleum and natural gas exploration and production activities are conducted jointly with others. These financial statements include only the Company's proportionate interest in such activities.

c) Measurement uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas properties, the provision for asset retirement obligations and the cost recovery ceiling test are based on estimates. These estimates include proven and probable reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the financial statements of future periods could be significant.

d) Cash and cash equivalents

Cash and cash equivalents include bank deposits and guaranteed investment certificates with original maturities of 90 days or less.

e) Petroleum and natural gas properties

Effective January 1, 2004, the Company adopted the new Canadian accounting guideline for oil and gas accounting using the full cost method. Under this new guideline, oil and gas assets are evaluated at least annually to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the oil and gas assets. If the carrying value of the oil and gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using a risk-free rate. The adoption of the new guideline had no impact on the Company's financial statements.

The proceeds of disposition of petroleum and natural gas properties are deducted from capitalized costs, with no gain or loss calculated unless such disposal would alter the depletion rate by 20 percent or more.

f) Depletion and depreciation

Costs related to petroleum and natural gas properties are depleted on the unit-of-production basis, based on the Company's gross share of total proven petroleum and natural gas reserves before royalties as determined by independent engineers. Costs eligible for depletion include total capitalized costs, less the cost of unproven properties, plus estimated future development costs of proven undeveloped reserves. Costs of acquiring and evaluating unproven properties are excluded from costs subject to depletion until it is determined whether proven reserves are attributable to the properties or impairment occurs. Natural gas volumes are converted to equivalent barrels of crude oil on the basis of relative energy content, where six thousand cubic feet of gas equates to one barrel of oil.

The costs of corporate and other capital assets are depreciated at rates approximating their useful life on a declining balance basis of 20 percent per year.

g) Asset retirement obligations

Effective January 1, 2004, the Company adopted the new Canadian accounting standard for asset retirement obligations. Under this new standard, the Company records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability and any remaining difference is recognized as a gain or loss to earnings in the period in which the settlement occurs. The impact of the adoption of the new standard is described in note 4.

h) Transportation costs

Effective January 1, 2004, transportation costs related to delivery of crude oil and natural gas are classified as an expense on the statement of earnings. In 2003 and prior years, transportation costs were recorded as a reduction to revenue. This change in classification has been applied retroactively and has no impact on net earnings, earnings per share or funds from operations.

i) Goodwill

Goodwill represents the excess of the cost of acquisitions (see note 2) over the net of the amounts assigned to assets acquired and liabilities assumed. Goodwill is not amortized. The Company monitors its goodwill balance to determine whether any impairment has occurred. If this review indicates that goodwill will not be recovered based on its fair value, the Company recognizes a write-down of the unamortized portion of goodwill in excess of the fair value.

j) Derivative financial instruments

The Company may utilize derivative financial instrument contracts to reduce its exposure to commodity price fluctuations. These contracts are designated, and are effective as, hedges and are not utilized for speculative purposes. Payments and receipts on these contracts are recognized in sales revenue at the time of sale of the related production.

For cash flow hedges, effectiveness is achieved if the changes in the cash flows of the derivative substantially offset the changes in the cash flows of the hedged position and the timing of the cash flows is similar. Effectiveness for fair value hedges is achieved if the fair value of the derivative substantially offsets changes in the fair value attributable to the hedged item. In the event that a derivative does not meet the designation or effectiveness criteria, the gain or loss on the derivative is recognized in earnings. If a derivative that qualifies as a hedge is settled early, the gain or loss at settlement is deferred and recognized when the gain or loss on the hedged transaction is recognized.

k) Revenue recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to a third party.

l) Income taxes

The Company uses the liability method of accounting for future income taxes. Under the liability method, future income tax assets and liabilities are determined based on "temporary differences" (differences between the accounting basis and the tax basis of the assets and liabilities), and are measured using the currently enacted, or substantively enacted, tax rates and laws expected to apply when these differences reverse. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

m) Stock-based compensation

The Company uses the fair value method for valuing stock options. Under this method, compensation cost attributable to stock options is measured at fair market value at the grant date and expensed over the vesting period, with a corresponding increase to contributed surplus. Upon exercise of the stock options, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital. Pursuant to the transition rules, the expense recognized applies to stock options granted on or after January 1, 2003. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest. Instead, the Company accounts for actual forfeitures as they occur.

n) Per share information

Basic per share information is calculated on the basis of the weighted average number of common shares outstanding during the year. Diluted per share amounts are calculated using the treasury stock method. Diluted calculations reflect the weighted average incremental common shares that would be issued upon exercise of dilutive options and warrants assuming the proceeds would be used to repurchase shares at average market prices for the year. Anti-dilutive options and warrants are not included in the calculation.

o) Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. The provision for future income taxes is increased and share capital is reduced by the renounced tax deductions when the expenditures are renounced.

2. Business combination

Effective September 30, 2004, the Company acquired all of the issued and outstanding shares of Sentra Resources Corporation ("Sentra"), an Alberta-based crude oil and natural gas exploration and production company, for $36.6 million. Consideration consisted of 4.7 million common shares at $7.48 per share and the fair value of Sentra options acquired, estimated at $0.1 million using the Black-Scholes option pricing model, in addition to transaction costs of $1.0 million. The purchase resulted in an excess purchase price over the fair value of assets acquired of approximately

$10.8 million which has been reflected as goodwill. The transaction has been accounted for using the purchase method, and the results of operations of Sentra are included in the statements of earnings and deficit from the date of acquisition.

The purchase price was allocated as follows:

($ thousands)	
Current assets	4,047
Property, plant and equipment	40,000
Goodwill	10,815
Current liabilities	(6,904)
Bank debt	(12,242)
Asset retirement obligations	(1,658)
Future income taxes	2,587
	36,645

3. Property, plant and equipment

December 31, 2004 ($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties			
Intangible	106,679	17,544	89,135
Tangible	15,118	2,486	12,632
Office equipment	351	87	264
	122,148	20,117	102,031

December 31, 2003 ($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties			
Intangible	35,218	5,041	30,177
Tangible	8,269	1,129	7,140
Office equipment	207	39	168
	43,694	6,209	37,485

Costs of undeveloped land amounting to $17.1 million at December 31, 2004 (2003 – $5.1 million) have been excluded from the depletion calculation, and future development costs of $3.3 million (2003 – $2.0 million) have been included in the depletion calculation.

On February 4, 2004, the Company completed the acquisition of producing assets and undeveloped land from a private oil and natural gas exploration and production company for consideration of $4.1 million.

The reference prices used in the full cost ceiling test calculation of the Company's crude oil and natural gas reserves at December 31, 2004 were:

	2005	2006	2007	2008	2009	2010	Thereafter
Crude Oil							
WTI US$ per barrel	42.00	39.50	37.00	35.00	34.50	34.30	+ 2.0%
Natural Gas							
Alberta AECO Spot Price							
Cdn$ per gigajoule	6.45	6.20	6.05	5.80	5.70	5.60	+ 2.0%

General and administrative expenses capitalized in 2004 amounted to $0.7 million (2003 – $0.5 million) of a total of $2.4 million (2003 – $1.6 million) in general and administrative expenses.

4. Asset retirement obligations

Effective January 1, 2004, the Company adopted the new Canadian accounting standard for asset retirement obligations as outlined in note 1.

The effect of this change in accounting policy has been recorded retroactively with restatement of prior periods. The effect of the adoption is presented below as net increases (decreases):

Balance sheet ($ thousands)	December 31 2003
Asset retirement costs, included in property, plant and equipment	664
Asset retirement obligations	785
Accumulated future removal and site restoration liability	(347)
Future income taxes	88
Retained earnings	138

Statement of earnings ($ thousands except per share amounts)	Year ended December 31 2003
Accretion expense	34
Depletion and depreciation on asset retirement costs	91
Amortization of estimated future removal and site restoration liability	(152)
Future income taxes	11
Net earnings impact	16
Net earnings per share – basic and diluted	–

The Company's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations is approximately $5.3 million as at December 31, 2004, which will be incurred over the next 15 years. The majority of the costs will be incurred between 2009 and 2019. A credit-adjusted risk-free rate of eight percent and an inflation rate of two percent were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the Company's asset retirement obligations is provided below

Year ended December 31 ($ thousands)	2004	2003
Balance, beginning of year	785	627
Liabilities incurred in period	464	135
Liabilities settled in period	(13)	(11)
Accretion expense	85	34
Sentra acquisition (note 2)	1,658	–
Balance, end of year	2,979	785

5. Share capital

a) Authorized

Unlimited number of voting Common Shares.

Unlimited number of voting First Preferred Shares, issuable in series, none of which have been issued.

Unlimited number of Second Preferred Shares, issuable in series, voting rights to be determined, none of which have been issued.

b) Issued

($ thousands except number of shares)	Number	Amount
Common shares		
Balance, December 31, 2002	12,503,040	38,943
Issued on exercise of stock options	99,710	232
Issued on exercise of performance warrants	4,000	12
Issued for cash, pursuant to private placement (note 5d)	1,500,000	9,000
Issue costs, net of future income tax effect of $206	–	(322)
Elimination of deficit through reduction of share capital (note 5e)	–	(4,057)
Balance, December 31, 2003	14,106,750	43,808
Issued on exercise of stock options	214,168	747
Issued on exercise of performance warrants	19,425	58
Issued on exercise of purchase warrants	675,000	4,050
Issued to effect business combination (note 2)	4,746,650	35,648
Issued for cash, pursuant to private placement (note 5d)	1,500,000	13,550
Issue costs, net of future income tax effect of $291	–	(440)
Balance, December 31, 2004	**21,261,993**	**97,421**

($ thousands except number of warrants)	Number	Exercise Value
Warrants		
Balance, December 31, 2002	408,333	1,225
Performance warrants exercised (note 5c)	(4,000)	(12)
Common share purchase warrants, issued pursuant to private placement (note 5d)	750,000	4,545
Balance, December 31, 2003	1,154,333	5,758
Performance warrants exercised (note 5c)	(19,425)	(58)
Common share purchase warrants exercised (note 5d)	(675,000)	(4,050)
Balance, December 31, 2004	459,908	1,650

c) Performance warrants

In June of 2002, 408,333 Performance Warrants were issued to management and to certain directors, officers, employees and consultants of the Company, contingent upon achieving certain performance targets. In September of 2002, the Performance Warrants became exercisable upon the achievement of the required performance criteria. Each Performance Warrant is exercisable into one Common Share at a price of $3.00 per Common Share and expires on June 12, 2007. As at December 31, 2004, a total of 384,908 Performance warrants remain outstanding.

d) Private placements

On December 15, 2004, the Company completed a private placement of 1,000,000 common shares at a price of $8.25 per share and 500,000 flow-through shares at a price of $10.60 per share for gross proceeds of $13.6 million.

On December 19, 2003, the Company completed a private placement of 1,500,000 units at $6.00 per unit for gross proceeds of $9.0 million. Each unit consisted of one common share and one-half of one common share purchase warrant. The warrants have a two year term and are exercisable at $6.00 per whole warrant prior to December 19, 2004 and $6.60 per whole warrant prior to December 19, 2005. All but 75,000 common share purchase warrants were exercised in 2004.

e) Reduction of share capital

Pursuant to a shareholders' resolution dated June 11, 2003, the stated capital of the Company was reduced by $4,057,040, being the cumulative deficit of the Company at January 1, 2003.

f) Stock option plan

Under the Company's stock option plan, the Company may grant options to purchase Common Shares up to the maximum number permitted by the Toronto Stock Exchange to directors, officers, employees and consultants. Options are granted at the market price, vest according to privileges set at the time the option is granted, and must expire no later than ten years from the date of grant.

As part of the business combination with Sentra (note 2), 217,500 replacement options exercisable at an average price of $12.96 were granted to former employees, officers and directors of Sentra who did not become employees, officers or directors of the Company. A total of 1,500 replacement options were exercised prior to the expiry date of December 29, 2004, when the remaining 216,000 replacement options were cancelled.

Following is a summary of options issued and outstanding at December 31, 2004 and 2003:

Issued:	2004			2003		
	Number of Options		Weighted Average Exercise Price	Number of Options		Weighted Average Exercise Price
Balance, beginning of year	1,341,295	$	2.99	1,266,671	$	2.79
Cancelled	(275,666)		(12.37)	(130,666)		(2.82)
Granted	1,050,000		8.74	305,000		3.53
Exercised	(214,168)		(3.14)	(99,710)		(2.33)
Balance, end of year	1,901,461	$	4.79	1,341,295	$	2.99
Exercisable, end of year	777,241	$	3.03	657,038	$	2.87

The following table summarizes information about stock options outstanding and exercisable at December 31, 2004:

	Options Outstanding		Options Exercisable		
Range of exercise price	Number Outstanding	Weighted Average Remaining Contractual Life	Number Exercisable		Weighted Average Exercise Price
$1.00 – $1.92	94,626	2.0 years	75,626	$	1.39
$2.56 – $3.25	839,397	2.4 years	586,510	$	2.97
$3.52 – $4.20	189,938	2.6 years	98,605	$	3.73
$6.00 – $6.36	108,500	4.1 years	5,500	$	6.25
$7.50 – $7.59	658,000	4.9 years	–	$	–
$12.50 – $12.50	11,000	0.9 years	11,000	$	12.50
$1.00 – $12.50	1,901,461	3.6 years	777,241	$	3.03

g) Per share amounts

In computing diluted earnings per share, 823,603 shares (2003 – 569,602) were added to the 15,504,582 (2003 – 12,587,386) weighted average number of common shares outstanding during the year for the dilutive effect of stock options and warrants. In 2004, 669,000 options (2003 – 750,000 warrants) to purchase common shares were not included in the computation because they were out of the money. No adjustments were required to reported earnings in computing diluted per share amounts.

The following table provides a summary of weighted average shares outstanding and per share earnings information:

	Year ended December 31	
	2004	2003
Weighted average common shares		
Basic	16,504,582	12,587,386
Diluted	16,328,185	13,156,988
Weighted average per share amounts		
Basic earnings	$ 0.09	$ 0.13
Diluted earnings	$ 0.09	$ 0.12

6. Bank debt

The Company has a credit facility with a Canadian chartered bank. The credit facility is a $24,000,000 revolving demand loan and bears interest at the bank's prime lending rate. The loan is secured by all of the Company's assets with a general security agreement.

7. Stock-based compensation

The Company uses the fair value method for recognizing a compensation cost for stock options granted subsequent to December 31, 2002.

The following table reconciles the Company's contributed surplus:

	Year ended December 31	
($ thousands)	2004	2003
Balance, beginning of year	500	310
Stock-based compensation expense	426	190
Stock options exercised	(75)	–
Balance, end of year	851	500

The Company continues to disclose the pro forma earnings impact of stock options granted in 2002. If the fair value method had been used for options granted in 2002, the Company's net earnings and net earnings per share for the years ended December 31, 2004 and 2003 would have been as follows:

($ thousands except per share amounts)	December 31, 2004 As Reported	December 31, 2004 Pro Forma
Net earnings	1,417	1,230
Earnings per share, basic	0.09	0.08
Earnings per share, diluted	0.09	0.08

($ thousands except per share amounts)	December 31, 2003 As Reported	December 31, 2003 Pro Forma
Net earnings	1,602	1,212
Earnings per share, basic	0.13	0.10
Earnings per share, diluted	0.12	0.09

In calculating the pro forma impact on net earnings, the fair value of options is amortized to compensation expense over the vesting period of the options.

The fair value of each option was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

	2004	2003
Expected life (years)	4.0	4.0
Risk-free interest rate (%)	3.5	4.1
Volatility (%)	48.1	51.9
Weighted average fair value of options granted ($)	3.06	1.58

8. Income taxes

The Company reports both federal capital tax and the Saskatchewan resource surcharge as capital tax expense. The provision for income taxes differs from the amount obtained by applying the combined Federal and Provincial income tax rate to earnings before income and other taxes as follows:

As at December 31 ($ thousands)	2004	2003
Statutory tax rate	39.85%	41.84%
Expected tax expense	1,097	920
Increase (decrease) resulting from		
Non-deductible Crown charges and other payments, net of Alberta Royalty Tax Credit	1,606	620
Federal resource allowance	(1,575)	(713)
Change in enacted tax rates	(23)	(370)
Other	(90)	(62)
Capital taxes	320	202
Income tax expense	1,335	597

The Company has $2.5 million of income tax losses available to reduce future taxable income which expire commencing in 2007.

The components of the net future income tax liability are as follows:

Year ended December 31 ($ thousands)	**2004**	2003
Property, plant and equipment	**(3,932)**	(3,816)
Non-capital losses	**950**	599
Asset retirement obligations	**1,036**	35
Share issue costs	**1,191**	565
Capital losses	**434**	434
Valuation allowance	**(434)**	(434)
	(755)	(2,617)

9. Financial instruments

The Company is exposed to fluctuations in commodity prices, interest rates and exchange rates. The Company monitors and, when approximate, utilizes financial instruments to manage its exposure to these risks.

a) Commodity price risk management

The Company periodically enters into oil and gas pricing agreements to provide it with exposure to a variety of pricing indices. At December 31, 2004, there were no oil and gas pricing agreements outstanding.

b) Foreign currency risk management

The Company is exposed to foreign currency fluctuations. The Company may periodically use financial instruments, including forward exchange contracts and currency options to manage this exposure. At December 31, 2004, there were no contracts or options outstanding.

c) Credit risk management

Accounts receivable include amounts receivable for oil and gas sales. These sales are generally made to large, credit-worthy purchasers. The Company views the credit risks on these items as insignificant. Amounts receivable for joint venture partners included in accounts receivable are recoverable from production and, accordingly, the Company views the credit risk on these amounts as insignificant.

d) Interest rate risk

The Company is exposed to interest rate risk to the extent that the bank debt is at a floating rate of interest.

e) Fair values of financial instruments

Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and bank debt have carrying values that approximate fair value due to the near term maturity of these financial instruments.

10. Supplemental cash flow information

Changes in non-cash working capital ($ thousands)	2004	2003
Accounts receivable	(1,681)	(5,134)
Accounts payable and accrued liabilities	4,755	3,186
Change in non-cash working capital	3,074	(1,948)
Relating to		
Operating activities		
Accounts receivable	116	(3,450)
Accounts payable and accrued liabilities	166	1,698
	282	(1,752)
Investing activities		
Accounts receivable	(1,799)	(1,682)
Accounts payable and accrued liabilities	(4,591)	1,486
	2,792	(196)
	3,074	(1,948)

Interest and taxes paid ($ thousands)	2004	2003
Interest paid	152	–
Income and other taxes paid	283	75

11. Commitments

The Company is committed to lease payments on office space as follows:

($ thousands)	2005	2006	2007	2008
Office leases	357	302	302	75

In 2004 the Company issued $5.3 million in flow-through common shares to investors and consequently, as at December 31, 2004, the Company is obligated to incur $5.3 million of qualifying expenditures prior to December 31, 2005.

12. Contingency

Sentra Resources Corporation was served with a statement of claim alleging breaches of contractual obligations in respect of a failed business combination in July 2004. The plaintiff alleges that by terminating plans for a business combination, Sentra is obligated to pay a break fee of $1.5 million. In addition, among other things, the plaintiff has also filed for punitive damages of $1.0 million. The Company does not believe any loss will be incurred as a result of this action and consequently, no provision has been recorded to these financial statements. Provision, if any, will be recorded in the period of determination.

Corporate information

Board of directors

VERNE JOHNSON [1][2][3]
President
KristErin Resources Ltd.
Calgary, Alberta

CARL-MARTIN NAGEL [1][2][3]
President
C.M. Nagel GmbH
Bad Vilbel, Germany

JAMES BANISTER [1][2][3]
President and
Chief Executive Officer
BanCor Inc.
Calgary, Alberta

CHRISTINA FEHR
Chief Executive Officer
Caribou Resources Corp.
Calgary, Alberta

RANDY PAWLIW
President and
Chief Executive Officer
Blue Mountain Energy Ltd.
Calgary, Alberta

(1) Member of the Audit Committee
(2) Member of the Reserves Committee
(3) Member of the Compensation Committee

Officers

RANDY PAWLIW
President and
Chief Executive Officer

BRENT FOSTER
Chief Operating Officer and
Vice President, Engineering

DALE JOYNT
Chief Financial Officer
and Corporate Secretary

Solicitors

BLAKE CASSELS & GRAYDON LLP
Calgary, Alberta

Bankers

CANADIAN IMPERIAL BANK OF COMMERCE
Calgary, Alberta

Auditors

KPMG LLP
Calgary, Alberta

Independent engineers

MCDANIEL & ASSOCIATES CONSULTANTS LTD.
Calgary, Alberta

Registrar and transfer agent

CIBC MELLON TRUST COMPANY
Calgary, Alberta

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